CORRECTED DIRECT TESTIMONY OF

PETER B. DAVID

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Peter B. David. I have been employed by Guidehouse (F/K/A Navigant Consulting, Inc.) since 2010, where I currently I am an Associate Director in the company's Energy, Sustainability, and Infrastructure practice. My business address is 150 N. Riverside Plaza, Suite 2100, Chicago, IL, 60606.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND EXPERIENCE.

A. I graduated from Colorado College in 2007 with a Bachelor of Arts in Physics with a minor in Math. I have over 10 years' experience with power systems modeling, economic analysis, utility resource and capacity expansion planning, renewable integration studies, and Monte-Carlo simulation, which is a method to test a large number of random scenarios to evaluate the risk of an event occurring. My experience includes evaluation of conventional, intermittent, and emerging technology energy resources across North America, the impact of these resources on electric reliability and system costs, and valuation of these assets in support of transactions. A copy of my curriculum vitae listing my professional credentials and experience is attached as Exhibit No. ___(PBD-1).

At Guidehouse, I lead our Wholesale Markets Analysis group within the Energy, Sustainability, and Infrastructure practice. I advise a wide array of different types of clients including utilities, state regulatory commissions, independent power producers, developers, Independent System Operators ("ISOs"), and other market participants on resource planning, market evolution, asset valuation, renewable curtailment risk, and strategy under uncertain conditions. I have led and supported multiple projects helping utilities and ISOs understand the challenges and changing requirements for power systems as intermittent energy resource penetration increases; as well as projects for renewable developers helping them understand long-term asset valuations and strategies in support of securing financing or being selected in a Request For Proposal ("RFP") process. Guidehouse regularly consults for municipal and cooperative utilities, state and federal agencies, investment funds, and other private entities. As a matter of practice, Guidehouse is committed to maintaining an independent and unbiased approach to its engagements.

Q. HAVE YOU PREVIOUSLY PRESENTED EXPERT TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. No, however, a major focus of my consulting and analytical work for many different clients over the course of my career has been analyzing the impacts of renewable integration for a number of market participants including both renewable investors and system operators. My expert analyses have been used for a variety of purposes including significant and major asset financing for developers as well as renewable capacity expansion planning for market stakeholders. The study that I conducted and present in this testimony is based upon collecting, analyzing, and understanding data and information of the type used in this case and the modeling that is integral to analyzing the data and conducting the study, all of which I am both intimately familiar and skilled by way of education, training, and experience.

PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide background and discuss the findings and conclusions contained in the June 2021 Guidehouse study titled "Variable Integration Cost" (the "Study") that was prepared on behalf of Dominion Energy South Carolina, Inc. ("DESC" or the "Company"). A copy of the Study is attached to my testimony as Exhibit No. ___ (PBD-2).

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized as follows:

- First, I provide background on the key concepts and definitions that are useful to understanding the operating challenges that variable generation causes for utilities and how mitigating those challenges adds costs.
- Second, I summarize the results of the Study.
- Third, I then explain the methodology Guidehouse used to develop the estimates of variable generation uncertainty, the analysis of the additional required Operating Reserves, and the forecast of the additional system cost from maintaining these Operating Reserves.

- Finally, I explain in greater detail the results of the Study and how Guidehouse developed the conclusions contained in the Study.

VARIABLE INTEGRATION COST STUDY BACKGROUND

Q. ARE THERE CERTAIN TERMS AND CONCEPTS THAT ARE USEFUL TO UNDERSTAND THE OPERATING CHALLENGES AND COSTS FOR INTEGRATING VARIABLE GENERATION ON THE DESC SYSTEM?

A. Yes. As part of my testimony, I use certain terms and concepts based on the below descriptions and definitions:

- "Operating Reserves" means the capability of the electric system to quickly increase generation in the event of mismatch between scheduled and actual generation or load caused by unexpected drops in generation or increases in load. Available Operating Reserves are calculated in terms of how much additional generation is available in a given period of time. For the purposes of the Study, Operating Reserves refers to the reserves needed to comply with the North American Electric Reliability Corporation's ("NERC's") 15-minute contingency reserve requirement.
- "Variable Generation" or "Intermittent Generation" refers to renewable resources such as wind and solar whose output varies based on prevailing weather patterns.

- "Variable Integration Cost" is the increase in costs to an electric system as a result of the need to carry more Operating Reserves in order to react to unexpected changes in renewable generation.
- "Renewable Forecast Error" is the variance between the planned renewable generation and the actual renewable generation.
- "Plant Cycling" is the act of turning an electric generating plant on and off in response to system needs.
- "Ramp Up/Down" is the act of increasing or decreasing generation at an electric generating plant.
- "Production Cost Model" is a class of energy system models designed to simulate detailed system operation over time. A production cost model simulates the dispatch of the electric system in such a way as to minimize overall system costs while serving load and respecting transmission, plant operating, and other system constraints.

Q. WHAT IS THE SCOPE AND PURPOSE OF THE STUDY?

A. Guidehouse conducted the Study in order to estimate the impacts that solar installations will have on DESC's system operations and determine the resulting incremental costs both for projects that are already under contract and have a variable integration charge clause in their Power Purchase Agreements ("PPAs") as well as potential future projects that are not already under contract.

To do this, the Study evaluated a baseline scenario as well as the Variable Integration Costs for three different scenarios of solar generation installed on the system. These scenario assumptions were developed to align with DESC's existing penetration, system needs, and internal studies. The baseline scenario includes all of the interconnected solar generation with PPAs that do not include any variable integration charge clauses (340 MW). The Tranche 1 scenario includes all of the baseline solar generation plus all of the interconnected solar generation with PPAs that do include a variable integration charge clause (633 MW incremental). The Tranche 2 and Tranche 3 scenarios include the solar generation with PPAs plus assumed tranches of future solar penetration that is not currently under contract or actively in development (100 MW and 300 MW incremental respectively). This is described in more detail by Company Witness Eric Bell. The specifics of the Study scenarios are shown in Table 1 below:

Table 1. Assumed Solar Generation on DESC System

Solar	**Cumulative Maximum Nameplate Facility Rating (MW)**		
	2022	2026	2031
Baseline Scenario	**340**	**340**	**340**
Tranche 1 Scenario	**973**	**973**	**973**
Tranche 2 Scenario	**1,073**	**1,073**	**1,073**
Tranche 3 Scenario	**1,373**	**1,373**	**1,373**

In addition to describing the Variable Integration Cost associated with each level of solar penetration, the Study describes the requirements that solar projects must meet in order to avoid the need for DESC to implement additional Operating Reserves and thus avoid any variable integration charge.

Q. WHAT ANALYSES DID GUIDEHOUSE UNDERTAKE IN PERFORMING THE STUDY?

A. The initial analysis focused on establishing a benchmark and baseline scenario for Guidehouse's PROMOD® production cost model that reflects DESC's actual system operating experience and the Company's own internal planning. The purpose of this initial analysis was to provide an appropriate and reasonable estimate of the Variable Integration Cost.

Next, Guidehouse conducted a solar uncertainty analysis, which estimated the forecast error for hourly generation from solar. The purpose of this analysis was to determine the amount of Operating Reserves that must be maintained by the Company in order to ensure that DESC can reliably respond to deviations from expectations and meet system needs if actual generation is less than forecasted.

Guidehouse developed a methodology for calculating the level of Operating Reserves required by the additional solar capacity utilizing the United States' National Renewable Energy Laboratory's ("NREL's") Solar and Wind Integration Data Sets. The NREL solar dataset includes one year of historical 5-minute generation data, 4-hour ahead scheduled generation, and latitude-longitude coordinates (wind resources are not relevant for this Study as there is no wind scheduled to be built in the latest DESC Integrated Resource Plan ("IRP")). Solar sites are selected corresponding to the actual portfolio of DESC, and then scaled according to the nameplate capacity of the solar plant. The marginal Operating Reserve requirement for each solar generator is then calculated as the delta between output minus scheduled using the NREL dataset as a proxy. Following this, the Operating Reserve requirement is summed across solar generators for each 5-minute interval in the forecast.

Ideally, the Study would rely on the difference between 1-hour ahead advance schedules and actual operations to estimate the marginal need for Operating Reserves created by solar resources; however, that data is unavailable. The 4-hour ahead advance schedule provides the best available proxy for a shorter-term advance schedule, and the Study mitigates the potential for overstating the necessary adjustment to the Operating Reserve requirement by eliminating the 10% of intervals with the highest observed increase in Operating Reserve requirements in each month.

The timeline for recovery from large imbalances in frequency due to loss of generation is governed by NERC's Reliability Based Control Standard BAL-002-2 as well as the Control Performance Standard 1 ("CPS1") portion of BAL-001-2. Recoveries from these imbalances are accomplished by employing contingency reserves, generally within 15 minutes. Thus, our definition of Operating Reserves is consistent with NERC's requirements.

Because of practical limitations associated with the size of the dataset, the model uses Monte Carlo draws to pick random days and records violations that last for more than 15 consecutive minutes. For each violation, the amount of Operating Reserves required to prevent a NERC violation are recorded. A key aspect of these draws is that they are simulated historical operation of the assumed resources including the impacts of regional weather and geographic diversity. This approach ensures that the cross-correlation of the variable generation is considered by randomizing the time period being drawn and pulling the operation of each resource from this period.

The maximum violation in each of these Monte Carlo draws is recorded and the highest 10 percent of violations are conservatively eliminated. We estimate the marginal Operating Reserve requirement for each level of solar penetration based on the highest remaining violations in each month. The Study relies on a 100-draw Monte Carlo simulation that is repeated 10 times and the final requirement by month is weighted by the number of draws for each month.

The analysis then considered the challenges the Company would experience if additional Operating Reserves were not added to the system. The Study provides examples and analyses of time periods when DESC operators would experience insufficient amounts of resources that would be needed to maintain system reliability.

Finally, while the Study focuses on the cost of providing additional Operating Reserves from existing resources, the Study also evaluated alternative mitigation options such as adding new resources to the system. This involved estimating the Company's cost to maintain additional resources necessary to integrate the intermittent energy generated by solar facilities. Another approach considered in the Study is the ability of solar projects to provide sufficient flexibility by way of incorporating on-site battery storage in order to mitigate forecast error so that DESC does not need to maintain additional Operating Reserves. The Study identifies measures that could be implemented to possibly reduce the impact of a project on DESC's Operating Reserve requirements

Q. HOW DOES THE VARIABILITY OF SOLAR GENERATION CAUSE ADDITIONAL OPERATING ISSUES FOR DESC?

A. Solar generation is an intermittent resource whose generation is significantly impacted by and dependent on weather, specifically when and how much the sun is shining, which are factors plant and system operators cannot control. Therefore, there is inherent uncertainty in how much electricity solar generating facilities will actually produce in a given hour. DESC operators, much like all other system operators in North America, must closely match generation and load at all times in order to ensure grid reliability. If there is less solar generation than was expected or scheduled, then DESC must have the ability to ramp up other generating facilities to replace the missing solar energy.

The ability to quickly ramp up generation in order to prevent a mismatch with load is an integral component of Operating Reserves. Operating Reserves are maintained by either keeping generators online but operating at less than their full capacity, an inherently less efficient and more expensive per megawatt-hour ("MWh") operating state than full capacity, in order to provide spinning reserves, or by maintaining non-synchronous generating resources that are capable of providing quick start reserves within 15 minutes. DESC operators also must balance the need to meet system load and to maintain sufficient Operating Reserves while operating its system in as reliable and efficient a manner as is possible.

Q. HOW DOES SOLAR GENERATION RESULT IN ADDITIONAL COST TO DESC'S SYSTEM?

A. When solar generation is added to the system without on-site battery storage or other self-mitigating solutions, DESC's operators must maintain additional Operating Reserves in order to ensure that, if actual solar generation is less than is scheduled or expected, the system can respond. This adds costs in one of two ways:

- The system operation must be changed from its previous minimum cost dispatch and operate less efficiently so that additional Operating Reserves are available to meet unanticipated changes in solar generation, resulting in increased variable operating costs.
- The Company must add new efficient resources to its system in order to maintain sufficient Operating Reserves to meet those needs, resulting in increased capital cost expenditures.

<u>VARIABLE INTEGRATION COST STUDY RESULTS SUMMARY</u>

Q. WHAT ARE THE STUDY'S FINDINGS AND CONCLUSIONS?

A. Guidehouse's findings and conclusions can be summarized as follows:

- Solar generation is an intermittent resource whose production depends on factors inherently outside of DESC's control such as prevailing weather conditions. As a result, it is possible for there to be significant variance between the amount of generation that is expected from solar versus actual solar output.

- The potential for solar forecast error introduces a measure of uncertainty to the generation needed from the rest of the system that increases as solar penetration increases.
- In order to account for this uncertainty and ensure that load and current Operating Reserve obligations are met, increased solar penetration will require DESC to maintain additional Operating Reserves beyond current requirements.
- Barring any other changes to the system, increasing the amount of Operating Reserves that DESC holds will change the way that the Company dispatches the system. Flexible generators, such as Combined Cycles ("CCs"), will have to frequently operate at levels below their maximum capability, which is less efficient and thus more expensive per MWh, in order to provide Operating Reserves. The energy those flexible assets would otherwise provide will instead come from less efficient and more expensive generators such as coal or gas-fired Steam Turbines or increased net imports. The end result is an overall increase in system operating costs.
- DESC currently has 340 MW of solar capacity under contract without a variable integration charge clause included in their PPAs. There is roughly 633 MW of solar capacity, bringing the total installed solar capacity up to 973 MW, that does have variable integration charge

clauses in their PPAs; the levelized cost of maintaining additional Operating Reserves for that tranche is $1.80/MWh

- As solar penetration increases, and thus the Operating Reserve requirement increases, the levelized cost of maintaining additional Operating Reserves also increases due to the need for DESC to operate the system in an increasingly less efficient manner. The levelized cost of maintaining additional Operating Reserves for the next 100 MW tranche of solar beyond what is currently contracted, bringing the total solar penetration to 1,073 MW, is $3.43/MWh; the levelized cost of maintaining additional Operating Reserves for a third tranche that includes an additional 300 MW of solar capacity, bringing the total installed solar capacity up to 1,373 MW, is $4.64/MWh.
- Building additional resources such as quick start Combustion Turbines ("CTs"), battery storage, or CCs to provide additional Operating Reserves will not reduce costs to DESC as the capital investment required for these facilities at current technology costs is far greater than the increase in system costs calculated in the Study.
- It is possible for solar projects to be added to the system that can mitigate their own potential forecast error by installing co-located battery storage or changing operations to be more flexible. Solar assets that do so will not require increasing Operating Reserve requirements and thus should not be subject to a variable integration

charge. The conditions for being able to self-mitigate forecast error need to be defined in detail but broadly require that:

- DESC can control the generation from the project so that it can curtail production if the solar forecast uncertainty requires withholding cost-effective generation which increases system dispatch costs.
- The project can make up the shortfall in generation by replacing all of the scheduled energy when called upon by DESC.

VARIABLE INTEGRATION COST STUDY METHODOLOGY

Q. WHAT APPROACH DID GUIDEHOUSE FOLLOW TO DERIVE ITS FINDINGS AND CONCLUSIONS?

A. A detailed description of the Study assumptions and methodology are provided in the report attached to my testimony as Exhibit No. ___ (PBD-2). The key aspects of the approach are summarized as follows:

- Guidehouse maintains a reference case forecast for all ISOs, RTOs, and NERC sub-regions that is updated twice a year, Guidehouse's spring 2021 reference case forecast was the starting point for this analysis. This reference case represents Guidehouse's independent view of the evolution of power markets across North America and incorporates near and long-term outlooks on demand and energy growth, generator additions and retirements, fuel prices, emissions prices, federal and state regulations, and transmission infrastructure investment.

- Guidehouse benchmarked its PROMOD® production cost model using information provided by the Company to verify or modify reference case assumptions in order to provide a baseline for the analysis.
- The solar forecast uncertainty was estimated by comparing the 4-hour ahead solar forecasts against 5-minute actual solar generation data from NREL as described above.
- The level of additional Operating Reserves that DESC needs to maintain was calculated as the maximum amount per day that solar could underproduce the forecasted amount. This value varies monthly driven by the fact that, during low-solar periods such as winter months, the forecast uncertainty is inherently lower than during high-solar periods because the amount of forecasted solar generation is lower and thus the potential mismatch between forecasted and actual generation is lower.
- Using PROMOD®, Guidehouse simulated system operation and production costs twice for each tranche of solar penetration, once with the additional Operating Reserve requirement and once without. The difference in production costs between the two cases, weighted by ~~hourly solar production~~whether or not solar is generating in each case, is the integration cost attributable to solar generation. Guidehouse then levelized the solar generation integration cost to produce a $/MWh value.

- Guidehouse evaluated the costs associated with adding additional resources capable of providing Operating Reserves, such as battery storage or gas CTs, to DESC's system as an alternative option for increasing Operating Reserves.
- Guidehouse evaluated options for a solar project to self-mitigate its potential forecast error in order to not increase DESC's Operating Reserve requirements.

Q. PLEASE DESCRIBE PROMOD®.

A. PROMOD® is a detailed hourly chronological market model that simulates the dispatch and operation of the wholesale electricity market. It is a widely-used industry-standard production cost model developed and licensed by ABB Ventyx. This model replicates the least-cost optimization decision criteria used by system operators and utilities in the market while observing generating operational limitations and transmission constraints. While PROMOD® can be run as a zonal or nodal model, Guidehouse exclusively runs it utilizing the full nodal model with full transmission representation.

As part of this analysis, PROMOD® also considers physical constraints of generation and fuel, emissions constraints, and Operating Reserve requirements. The software takes into account the operational advantages and disadvantages of each generation type and quantifies the cost impact of forcing operation away from the most economical way in which to operate the system.

Q. WHAT ASSUMPTIONS DID GUIDEHOUSE USE REGARDING THE AMOUNT OF SOLAR GENERATION ON DESC'S SYSTEM?

A. In conducting the Study, Guidehouse considered a baseline case and three scenarios representing three additional tranches of solar projects. The baseline case includes the 340 MW of solar that is currently contracted by DESC with no variable integration charge clause in their PPAs. Trance 1 includes 633 MW of solar (for a total of 973 MW) that is currently contracted by DESC with an interim variable integration charge clause subject to true-up. Tranche 2 includes 100 MW more of solar, bringing the total solar capacity up to 1,073 MW. Tranche 3 includes an additional 300 MW of solar, bringing the total solar capacity up to 1,373 MW. The additional solar capacity modeled in the second and third tranches represents potential future solar penetration and is not tied to any specific assets currently under considerations, the amount of solar capacity included in these tranches was set to match those considered in DESC's avoided cost study.

Q. WHAT IS THE IMPACT IF MORE SOLAR IS ADDED TO THE DESC SYSTEM THAN IS CONSIDERED IN THE STUDY?

A. As more solar capacity is installed and integrated into the Company's system, DESC will need to hold an increasing amount of Operating Reserves to integrate it. While Guidehouse did not attempt to quantify the impact of integrating more solar onto the Company's system than is considered in this Study, the prevailing trends that Guidehouse observed in conducting the Study lead to the conclusion that, barring further changes to the system, system costs will increase at a faster pace than Operating Reserve requirements due to increasingly less efficient (and thus more expensive) resources needing to be called on more frequently to allow for flexible resources to provide Operating Reserves.

Q. PLEASE DESCRIBE THE IMPACT OF GEOGRAPHIC DIVERSITY OF RENEWABLE RESOURCES AND THE IMPORTANCE OF INCLUDING IT IN THE STUDY.

A. The concept of geographic diversity recognizes that solar generation is not located in a single area, but in different places through a system. Since weather can vary significantly between locations, geographic diversity means that there is variability in how weather will affect the generation output of dispersed solar installations at any given time and thus reduces the potential impact of forecast error.

Incorporating geographic diversity is an important component of the Study, as it reduces the total amount of uncertainty facing DESC. In a system with a larger geographic footprint and thus greater geographical diversity, the potential for forecast error driven by weather patterns would be less and the need to increase Operating Reserves to support integration would be reduced. While there is not a significant amount of geographic diversity impacting a region as compact as DESC, it is still an important factor to consider. For the Study, geographic diversity was included in all phases of the analysis, including actual data from 40 solar sites inside of the Company's footprint. If geographic diversity had not been considered in this Study, the potential for forecast error would have been greater, which would have led to a higher Operating Reserve requirement for the Company, which in turn could have led to estimated integration costs being incorrect as the forecast error for a single solar site could be significantly different than the aggregate forecast error for an array of geographically diverse sites. This concept should not be confused with the potential need for siting generators in specific locations based on proximity to load, as that is a separate consideration when determining appropriate sites for capacity expansion.

Q. WHAT LEVELS OF OPERATING RESERVES DID GUIDEHOUSE STUDY FOR EACH OF THE SOLAR PENETRATION SCENARIOS AND WHY?

A. The analysis of solar uncertainty on the DESC system showed that forecast error for 4-hour ahead solar scheduling is dependent upon the time of year. As a result, the amount of Operating Reserves that DESC needs to maintain when committing units varies by month. Table 2 below shows the level of Operating Reserves needed in each month based on the level of solar penetration. The baseline Operating Reserves are the Operating Reserves currently needed to satisfy VACAR and native load requirements, and to safely and reliably serve the load on the company's system. The Operating Reserves for each tranche are cumulative, the table shows the Operating Reserves needed for the total amount of solar capacity installed in the tranche inclusive of the solar capacity modeled for the prior tranche.

Table 2: Operating Reserves Needed to Maintain Reliability[1]

Month	Baseline (340 MW Installed Solar Capacity)	Tranche 1 (973 MW Installed Solar Capacity)	Tranche 2 (1,073 MW Installed Solar Capacity)	Tranche 3 (1,373 MW Installed Solar Capacity)
Jan	250	494	565	744
Feb	250	588	627	834
Mar	250	623	670	889
Apr	250	632	699	895
May	250	608	695	884
Jun	250	581	649	827
Jul	250	561	627	794
Aug	250	557	607	774
Sep	250	554	603	798
Oct	250	549	605	784
Nov	250	525	573	737
Dec	250	483	537	653

Because the solar forecast is not the same in every hour, DESC's Operating Reserve requirement will not be the same in every hour. For example, during

1 The Baseline Operating Reserve requirement is the current requirement, as provided by DESC.

overnight non-solar hours the Operating Reserve requirement would not be any greater than the baseline requirement regardless of installed solar capacity. In order to account for this, Guidehouse weighted its analysis of changes on production cost based on ~~hourly solar generation~~whether or not solar is generating. Impacts to production costs driven by increases to Operating Reserve requirements during non-solar hours are excluded from this analysis~~ and impacts during hours in which solar generation is high are weighted more heavily than impacts during hours in which solar generation is low~~.

Q. WILL UTILITY COSTS INCREASE AS A RESULT OF INTEGRATING SOLAR GENERATION ON AN ELECTRIC SYSTEM?

A. Yes, solar integration will increase utility costs related to Operating Reserves. The increased Operating Reserve requirements driven by solar integration will change the way that a system must be operated. A few examples of how the increased Operating Reserve requirement associated with integrating solar generation can increase utility costs include:

- Increased fuel costs as flexible generating assets are required to operate at less-than-optimal efficiency levels, and less efficient assets such as CTs, coal or gas-fired Steam Turbines are called upon to provide energy more frequently.

- Increased start-up costs, both from start fuel and non-fuel operations and maintenance ("O&M") costs associated with starts, due to an increased need to cycle units on and off more frequently.
- Increased variable O&M costs driven both by generating units with higher variable costs being dispatched more frequently, either to provide Operating Reserves or to allow other flexible generators to provide Operating Reserves, as well as additional stress that is placed on units that are ramping to follow solar generation.
- Costs associated with emissions can increase if the units whose operations increase have higher emissions expenses per MWh than those whose operations are ramped down to provide Operating Reserves.
- Finally, a utility's capital costs will increase if it meets increased Operating Reserve requirements by adding new generating resources or by capital investments to its existing generating fleet in order to increase flexibility.

Q. DOES THE STUDY CONSIDER SYSTEM COSTS FOR SCENARIOS WITH DIFFERENT LEVELS OF OPERATING RESERVES?

A. No. The Study calculates the Operating Reserve levels as the maximum daily potential forecast error of solar generation at each level of solar penetration. This maximum is constant by year but varies by month. In real world operations, there will be days within a month in which solar generation is forecasted to be lower than average, which reduces the potential for error and thus reduces the Operating

Reserve requirement for those days. PROMOD® does not allow for Operating Reserve levels to change day-to-day, only monthly, so in order to account for this and prevent a biased estimate of integration costs Guidehouse weighted the change in operating costs due to increased Operating Reserve levels by ~~the hourly forecasted solar generation~~whether or not solar is generating. This weighting ensures that the Study does not overestimate integration costs.

Q. DOES THE STUDY CONSIDER THE POSSIBILITY OF CHANGING HOW THE COMPANY'S FAIRFIELD PUMPED STORAGE OPERATES IN ORDER TO INTEGRATE SOLAR GENERATION?

A. Yes. In the Study, the Fairfield Pumped Storage asset is modeled in PROMOD® in a way that allows it to modify operations in order to minimize overall system costs. The pumped storage is able to both (1) provide Operating Reserves when called on, and (2) generate energy to reduce the net load that must be met by the Company's other generating assets. The Variable Integration Costs presented in the Study therefore reflect the company's ability to change Fairfield Pumped Storage's operations however is necessary to reduce system costs.

VARIABLE INTEGRATION COST STUDY CONCLUSIONS

Q. BASED ON THE STUDY, WHAT IS THE INTEGRATION COST FOR VARIABLE GENERATION ON THE DESC SYSTEM FOR ADDITIONAL TRANCHES OF SOLAR RESOURCES?

A. As indicated previously, integration costs for variable generation increase as variable generation increases. While Guidehouse calculated the integration costs for the first tranche of solar to be \$1.80/MWh, the integration costs for the next 100 MW of solar would be \$3.43/MWh while the integration costs for a 3rd tranche of solar comprising 300 MW of capacity would be \$4.64/MWh. Table 3 below shows the calculation of the incremental costs for each tranche.

Table 3: Variable Integration Costs on DESC's System

	Tranche 1	**Tranche 2**	**Tranche 3**
Cost Difference NPV (\$)	\$23,613,398	\$6,952,589	\$27,866,728
Incremental Solar Generation (MWh)	13,135,941	2,026,960	6,013,322
Levelized Cost (\$/MWh)	\$1.80	\$3.43	\$4.64

Q. DOES THE SYSTEM COST CHANGE AS ADDITIONAL RESERVES ARE MAINTAINED?

A. Yes. In every solar penetration case analyzed for the Study, when the Company's Operating Reserve requirement increases, total system costs and levelized integration costs for solar also increase.

Q. IS IT POSSIBLE FOR DESC TO REDUCE ITS COSTS TO INTEGRATE VARIABLE GENERATION BY ADDING BATTERY STORAGE OR NEW CT GAS UNITS SOLELY TO PROVIDE RESERVES?

A. No. At this time adding additional resources solely to provide Operating Reserves is not a cost-effective approach to lowering the variable integration costs associated with increased solar penetration. While adding additional battery storage or CT Gas units would eliminate the company's need to operate the system in a less efficient manner in order to provide the additional Operating Reserves required by increased solar penetration and thus negate the expected increase to operating costs, the capital expenditure required to add enough battery storage or CT Gas capacity to provide the necessary Operating Reserves is significantly greater than costs associated with modifying operations of the existing system. The levelized cost of integrating the first tranche of solar tested in the Study of approximately $23.6 million is equivalent to the cost of adding approximately 33 MW of CT Gas, 21 MW of 2-hour battery, or 13 MW of 4-hour battery capacity; none of which is sufficient to provide the Operating Reserves needed to integrate the solar capacity.

Further detail regarding overnight capital costs for different generating technologies is presented in the Study which is attached to my testimony as Exhibit No. ___ (PBD-2).

In order to meet the increased Operating Reserve requirement for the first tranche of solar penetration tested in the Study through new capacity additions alone, DESC would need to add roughly 382 MW of CT gas or battery storage capacity. Depending on how much of each technology the company were to acquire, that would require a capital investment ranging between $271 million and $718 million. While acquiring new, efficient capacity would have benefits to DESC and its customers, such as decreasing overall production costs, that are not evaluated in the Study, the capital investment required to acquire that level of capacity is far greater than the benefits it could reasonably be expected to produce.

Q. IS IT POSSIBLE FOR SOLAR PROJECTS TO INTERCONNECT TO THE DESC SYSTEM WITHOUT INCREASING RESERVE REQUIREMENTS?

A. Yes, the conditions need to be defined in detail but broadly require that:

- DESC can control the generation from the project so that it can curtail production if the solar forecast uncertainty requires withholding cost-effective generation which increases system dispatch costs.
- The project can make up the shortfall in generation by replacing all of the scheduled energy when called upon by DESC.

Examples of projects that might be able to meet these conditions include solar projects co-located with battery storage or solar configured to operate flexibly.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Peter B. David

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Professional Summary

Peter B. David is an Associate Director with the West Markets group of Guidehouse's Energy, Sustainability, and Infrastructure practice. His expertise is in Physics. Mr. David leads the Wholesale Energy Markets Analysis team.

Mr. David is the lead PROMOD modeler for Guidehouse's Wholesale Markets Analysis team and also directs engagements using Guidehouse's proprietary Electric Valuation Model (EVM), which calculates forecast hourly dispatch for individual units capturing additional measures of volatility not accounted for in the fundamental forecast. Mr. David leads and supports a wide variety of client projects as well as the semi-annual reference case outlook for all 3 North American interconnections, which includes both PROMOD forecasts and the creation of off-the-shelf reports detailing current and forecast conditions in energy markets. Mr. David has more than 10 years of experience in production cost modeling, conducting market research, analyzing locations for potential future generator expansion siting throughout NERC, and analyzing potential renewable resource expansion plans based on varying future rules and regulations, economic conditions, and renewable capacity targets. Mr. David has a Bachelor's degree in Physics from Colorado College.

Guidehouse

Peter B. David

Associate Director

Areas of Expertise

- **Capacity Expansion Planning**: Uses internally-created LCOE models, publically available load forecasts and RPS requirements, and a deep understanding of North American wholesale power markets to create regional long-term capacity expansion plans
- **Wholesale Power Market Forecasting**: Uses PROMOD to model wholesale power markets on a nodal level in EI, ERCOT and WECC
- **Single Unit Dispatch Analysis**: Conducts merchant hourly dispatch analyses for a single generating unit modeled as a price taker
- **Curtailment Risk Analysis**: Conducts curtailment risk analysis studies for renewable generators
- **Data Mining and Analysis**: performs research and in-depth data analysis identifying market trends and opportunities

Professional Experience

Capacity Expansion Planning

- Leads research efforts to determine regional load forecasts, renewable capacity targets, economic conditions, and emissions regulations
- Uses LCOE models and other proprietary portfolio optimization tools in order to create regional capacity expansion plans that account for emissions targets, load growth, and expected generator retirements while maintaining grid reliability and minimizing overall system costs

Wholesale Power Market Forecasting

- Operates PROMOD on a nodal level to simulate market operations interconnect-wide in EI, ERCOT and WECC through 2045
- Manages Guidehouse's energy market reference cases
- Contributes to the Energy Market Modeling team by conducting research for the models and market overviews and supporting analysis for the client reports.

Single Unit Dispatch Analysis

- Primary operator of Guidehouse's proprietary Electric Valuation Model (EVM), used to simulate the dispatch of a single merchant generator as a price taker
- Uses technical expertise to build and define plant operating parameters within EVM and analyze, identify potential problems, and analyze and explain results.

Curtailment Risk Analysis

- Uses PROMOD nodal forecasts to identify potential curtailment risk for renewable generators based on the nodal price, curtailment price, and operating characteristics of the renewable plant

Peter B. David

Associate Director

- Identifies, designs, and implements scenarios within PROMOD around changes to transmission infrastructure, demand forecasts, total renewable penetration, and other factors that could impact a renewable generator's curtailment risk.

Data Mining and Analysis

- Expert in Microsoft Office Suite, proficient in Microsoft Access and SQL
- Scrapes data from a multitude of sources including SNL, ABB's Energy Velocity Suite, IRP's, and ISO / RTO websites in order to identify and respond to market trends

Work History

- Associate Director, Guidehouse

Education

- Bachelor of Arts, Physics, Colorado College

Variable Integration Cost

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June 29, 2021

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Executive Summary

Guidehouse, Inc (Guidehouse) was retained by Dominion Energy South Carolina, Inc. (DESC) to determine the variable integration cost (VIC) associated with intermittent renewable generation.

To ensure the electric grid operates reliably, utilities are required by North America Electric Reliability Corporation (NERC) to hold operational reserves and ramping capability to balance the system in the event of unforeseen changes in either load or generation.

As additional intermittent solar generation is added to the system, the amount of unpredictable generation increases requiring the utility to hold more operating reserves and potentially operate its system less economically. The purpose of this study is to assess the incremental costs (VIC) of maintaining these additional reserves so that the utility and regulators can make informed decisions as to how the costs should be allocated between new solar generators and DESC customers.

In this report, Guidehouse presents the study methodologies and results to determine the VIC associated with increasing amount of solar capacity on the DESC system. A significant component of the VIC study is determining how reserve requirements change with different levels of solar penetration. Inputs from DESC include operational parameters of existing units, long-term build on the system, and the levels of solar penetration to evaluate the VIC. All other modeling inputs are from Guidehouse and any outputs and analysis were conducted independently.

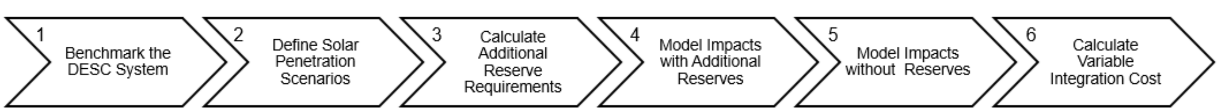
Study Approach

Guidehouse maintains a Reference Case forecast, updated biannually, of all energy markets across North America covered by the NERC. The Reference Case is Guidehouse's view of the most probable evolution of markets over the next 25 years. It is prepared on a long-term nodal basis, which includes detailed modeling of regional power and transmission systems. The most recent Reference Case, Spring 2021, is utilized for this analysis.

Guidehouse uses PROMOD, a commercially available production cost model, to assess the impact of solar generation on DESC's existing generation and operating requirements, including the VIC incurred due to solar load offsets and variable output. These impacts include additional production costs and ancillary services (such as incremental operating reserves) resulting from large additions of solar capacity.

A high level summary of the study approach is shown below. More detail around methodology and assumptions can be found in Section 2.

Figure 1. VIC Study Approach



1. **Benchmark the DESC System** – Guidehouse's Spring 2021 Reference Case was updated with more unit-specific operational parameters provided by the DESC team. The first few years of the model were compared to actual historical generation to align specific unit operations.
2. **Define Levels of Solar Penetration** –There are 973 MW of solar projects that have current contracts with DESC, including approximately 633 MW containing VIC contractual clauses. The remaining 340 MW of contracts do not have a VIC clause and serve as the baseline for this analysis. Guidehouse evaluated the following levels of solar penetration to account for both current solar resources under contract and potential future additions.
    a. Tranche 1: +632 MW (341 to 973 MW)
    b. Tranche 2: +100 MW (974 to 1073 MW)
    c. Tranche 3: +300 MW (1074 to 1373 MW)
3. **Calculate Reserve Requirements** – DESC needs to hold sufficient reserves to be able to respond to the worst-case downward variance of solar generation while maintaining overall system reliability. An approach was developed to forecast the amount of load-following reserves needed with increasing renewable penetration based the National Renewable Energy Laboratory's (NREL) Solar Integration Data Sets. A key aspect of this calculation is that the potential solar forecast error which drives increases reserve requirements in order to integrate intermittent solar capacity is simulated based on historical operation of the assumed resources including the impacts of regional weather and geographic diversity. As DESC integrates larger amounts of solar and can obtain actual historical data for solar in upcoming years, this analysis can be updated with actual site-specific solar operations rather than data provided by NREL.

    The incremental additional reserves need for each level of solar capacity are in Table 1.

Table 1. Incremental MW Reserves Required by Solar Tranche

Month	Baseline (340 MW Solar)	Tranche 1 (341 to 973 MW)	Tranche 2 (974 to 1073 MW)	Tranche 3 (1074 to 1373 MW)
1	250	244.1	70.9	178.7
2	250	337.9	38.8	207.3
3	250	373.1	47.1	219.1
4	250	382.0	67.1	196.1
5	250	357.6	87.3	189.4
6	250	330.5	68.3	178.6
7	250	310.8	66.6	167.0
8	250	306.9	50.4	166.2
9	250	304.4	48.1	195.1
10	250	298.9	55.9	178.8
11	250	275.2	47.3	164.0
12	250	233.1	53.8	116.3

Source: Guidehouse Study for DESC, June 2021

4. **Model System Impacts With Additional Reserves –** PROMOD is run with the additional reserves required and calculate the total production costs, including net imports and exports, for each hour during the forecast.
5. **Model System Impacts Without Additional Reserves –** PROMOD is run without the additional reserves required (i.e. use the reserve requirement of the previous tranche) and calculate the total production costs, including net imports and exports, for each hour during the forecast.
6. **Calculate the Variable Integration Cost –** The difference between total production cost ~~during solar generation hours only is taken and~~ weighted by whether or not there is any solar generation, and then summed and then divided by the total solar generation for each year to produce a VIC for that year.[1] The value is then levelized by taking the net present value, assuming a 8.5797% discount rate[2], and divided by the number of years in the study period.

The Variable Integration Cost

DESC operators must ensure that both system load and operating reserves are met in all normal conditions.

As additional intermittent solar generation is added to the system, the amount of unpredictable generation increases which requires the utility to hold more operating reserves and ramping capabilities to meet potential shortfalls in actual solar generation compared to the forecast. Solar generation steadily increases in the morning, peaks throughout the day, and decreases as the sun sets. The intermittency in generation can lead to both reliability and load issues in the event that actual generation is higher or lower than the forecast when scheduling non-intermittent generators.

Non-intermittent generators will shift operations to meet load and reliability in order to meet these mismatches. As a result, if the appropriate amount of operating reserves is not held on the system when mismatches arise, then reliability violations may occur. When planning its system operations, DESC is provided a solar forecast and must plan for the worst-case scenario. This means that the utility must hold sufficient reserves in each case to be able to respond to the worst-case drop in solar given the forecast.

A foundational principle of this study is that DESC will have to change its system's operation to ensure that these reserves can be met. There are three potential operational implications for DESC:

- There may already be sufficient online flexibility to meet the additional reserves, in which case there would be no change to the operation.

[1] PROMOD is only capable of modeling a varying reserve requirement by month, not on hourly basis. The VIC is ~~solar generation-weighted~~weighted by whether or not solar is generating to avoid the biases that may arise when modeling an increased reserve requirement around the clock. ~~For example, the difference in total production costs during a midday hour where there is peak solar generation is weighted proportionality more than a shoulder hour when there is less solar generation.~~ This calculation excludes overnight hours where solar generation is zero.

[2] The discount rate was provided by DESC. It is consistent with any internal IRP and avoided cost modeling.

- It may be necessary to generate more energy from less efficient resources to ensure that other units that can provide ramping capabilities are at less than full capacity and available to provide reserves.
- It may be necessary to startup less efficient generation in order to be able to provide the reserves.

The costs associated with the changes to system operation associated with the additional procurement of reserves is known as a VIC. The levelized VIC over the forecast period between 2022 to 2031 for each Tranche is presented in Table 2.

Table 2. Variable Integration Cost by Solar Tranche

Solar Tranche	VIC ($/MWh)
Tranche 1 (341 to 973 MW)	$1.8016
Tranche 2 (974 to 1073 MW)	$3.4301
Tranche 3 (1074 to 1373 MW)	$4.6345

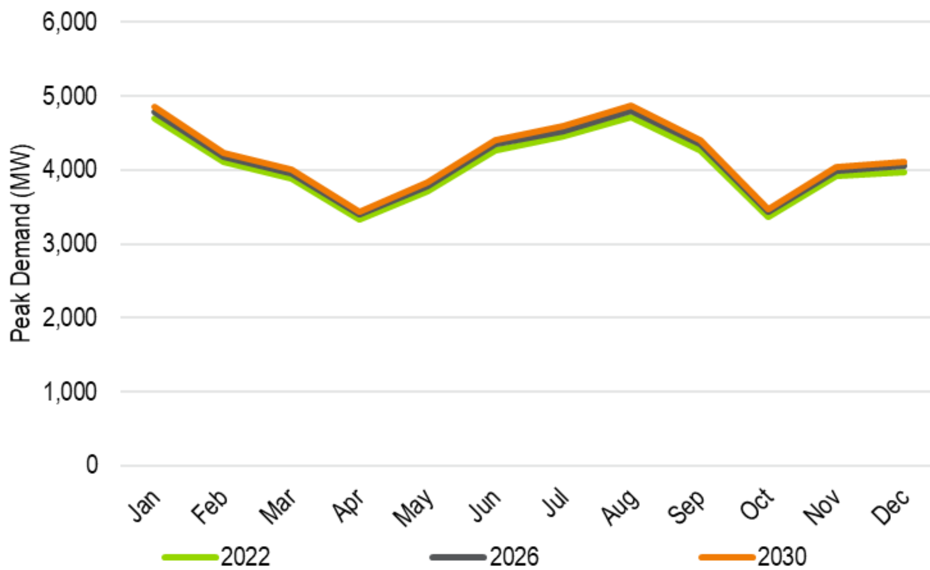
Source: Guidehouse Study for DESC, June 2021

1. Impact of Solar

1.1 The Dominion Energy South Carolina Power System

DESC provides electric services for a large portion of South Carolina, with hourly net demand typically ranging between 2,500 MW and 3,100 MW, and monthly peak demand typically between 3,250 MW and 5,000 MW. DESC forecasts both winter and summer peaks, as shown in Figure 2, with the highest demand occurring during January and August. This trend is expected to remain consistent over time.

Figure 2. Monthly DESC Peak Demand



Source: Dominion Energy South Carolina, Modified 2020 Integrated Resource Plan

DESC operators must ensure that both system load and operating reserves are met in all normal conditions. DESC is required to hold 200 MW of reserves at all times to meet their requirements within VACAR South Reserve Sharing Arrangement (VACAR) to be able to respond to the loss of the single-largest unit on the system[3]. An additional 50MW of reserves are held for load-following. Due to the need for self-sufficiency within its balancing area, DESC must rely on its own generators to meet reserves and cannot rely on external sources.

Reserve requirements are met by operating the system such that generators can be called upon to quickly reach the levels of the reserve requirement. For example, many of DESC's combustion turbine (CT) units can start within 15 minutes. These units provide reserves even when they are not operating. However, combined cycle (CC) units are much larger and require more than an hour to start if they are not operating, so these units can only provide reserves if they are turned on and operating below their full capability. However, this is less efficient from both an economic and environmental perspective than operating at full capacity.

[3] VACAR is a reserve sharing agreement that Dominion Energy South Carolina is a part of. Being part of VACAR helps DESC maintain sufficient contingency reserves in order to respond to the single largest contingency on the system without having to hold all of the reserve requirement. The 200 MW of reserves for DESC is its share of these contingency reserves.

A summary of DESC's non-solar resources can be found in Table 3.

Table 3. Summary of DESC Resources

Technology	Nameplate Capacity (MW)	Quick-Start
Combined Cycle	1,979	No
CT Gas	399	Yes
ST Gas[1]	761	No
ST Coal[1]	1,294	No
Nuclear	662	No
Hydro	224	No
Pumped Storage	576	No

1. The Cope Steam Turbine plant runs on natural gas during the summer and on coal during winter, due to fuel availability, counted toward ST Gas in this table.

Source: Dominion Energy South Carolina

Compared to some other power systems nearby, DESC has a high proportion of "baseload" generating capability from nuclear and coal plants. The key characteristic of baseload plants is that they have limited ability to change their generation quickly and are unable to startup or shutdown without a long lead-time.

1.2 Changes to System Operation with Solar

Non-intermittent generators will shift operations to meet load and reliability criteria as the amount of intermittent solar capacity within the DESC system increases. Expected solar generation steadily increases in the morning, peaks throughout the day, and decreases as the sun sets; however, generation being dependent on weather conditions can lead to measurable output variances from forecasts. The unpredictability and intermittency of solar (as DESC cannot control when the sun shines) can lead to both reliability and load issues in the event that solar generation is higher or lower than forecast when scheduling other non-intermittent generators.

If actual solar generation is higher than forecast, the following may occur: 1) non-intermittent generators turn down, 2) excess generation is exported to a neighboring region, or 3) as a last resort, absent another option to avoid a system emergency, solar generation is curtailed.

If actual solar generation is less than forecast, DESC must ramp up generation from reserves to maintain operations and meet load. The amount of reserves required is determined by the total solar capacity on the system and the magnitude of a potential shortfall from forecasted solar generation. As solar capacity is added onto the system, the magnitude of a potential shortfall increases and thus DESC must procure and hold additional reserves above current requirements.

One foundational principle of this study is that DESC will have to change systems operations to ensure that these reserves can be met, and reliability can be maintained. Depending on several factors, there are three potential operational implications outcomes for DESC including:

- There may already be sufficient online flexibility to meet the additional reserves in which case there would be no required change to system operation.

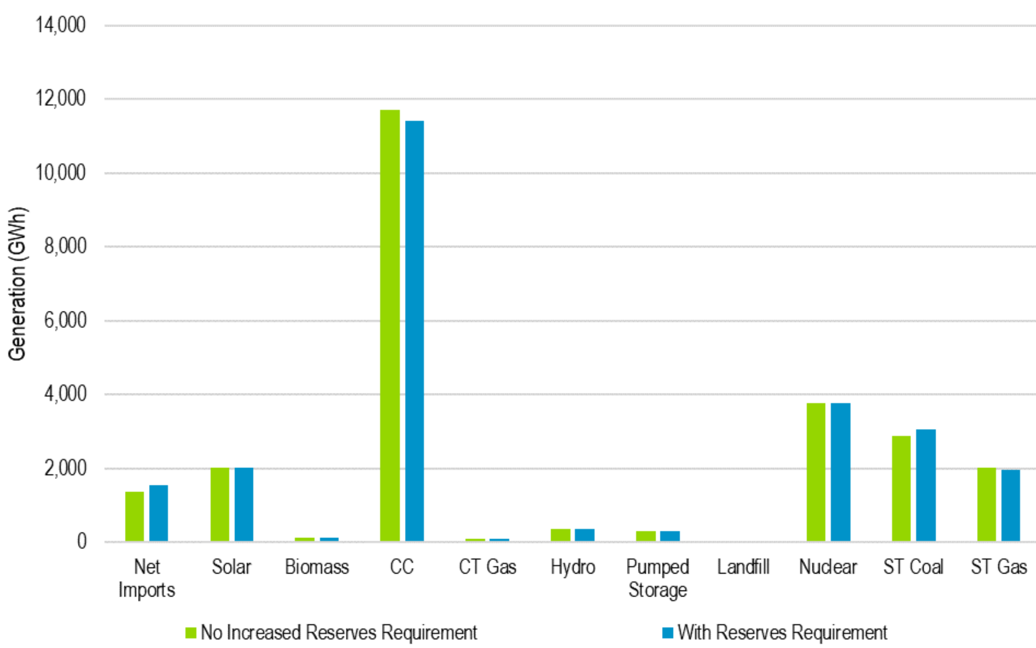
- It may be necessary to increase generation from less efficient resources to ensure that other units that can provide ramping capabilities are operating at less than full capacity and available to provide reserves.
- It may be necessary to startup less efficient generation in order to be able to provide the reserves.

The costs associated with the changes to system operation associated with the additional procurement of reserves is known as a variable integration cost (VIC).[4]

The lowest cost to operate the DESC system, given current reserve requirements, is to have the CC fleet generate at almost full capacity while providing a few reserves. Most of the system reserves are provided by Saluda and the CT gas units. When additional reserves are needed, the operators must decrease output from the CC units to provide reserves and increase output from steam turbine (ST) coal and gas units to provide energy. This increases the cost to operate the system.

Figure 3 shows total annual generation by fuel source for DESC in 2025 with and without an increased reserve requirement for a scenario in which DESC's total installed solar capacity is 973 MW. Total generation from CC's decreases when the reserve requirement increases, the CC fleet must now provide reserves in some hours and the generation is made up by an increase both in net imports and increased generation from ST coal units. All other generation is relatively constant between the runs. As discussed previously, this increases the overall cost to operate the system.

Figure 3. Supply by Source in 2025, 973 MW Installed Solar Capacity



Source: Guidehouse Study for DESC, June 2021

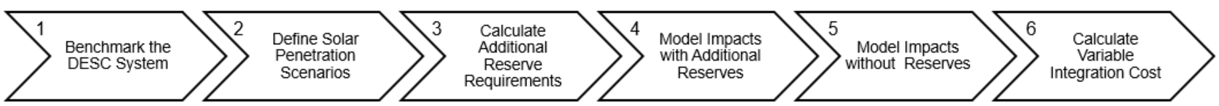
[4] Wind capacity and generation shortfall is also included in the variable integration cost. However, the DESC does not currently nor is expected to procure any wind capacity in this study.

2. Study Methodology

Guidehouse used the six-step approach shown in Figure 4 to calculate the VIC at various solar penetration levels. In order to calculate the VIC, Guidehouse had to determine the amount of reserves required for each varying level of additional solar capacity, as discussed in Section 1. Guidehouse then modeled how the DESC system is dispatched under two scenarios using PROMOD, a production cost model, for each level of solar penetration. The first scenario is without the additional reserve requirement, and the second scenario is with the additional reserve requirement. Between the two scenarios, everything is held constant except for the amount of reserves that DESC would require. The difference between the total cost to serve system load under each scenario then becomes the basis for the VIC.

The study forecasts the levelized VIC for the system over 10 years from 2022 through 2031. This section describes the study methodology and assumptions in detail. A high level summary of the study approach is shown below, and a description of Guidehouse's market modeling process can be found in Appendix A.

Figure 4. VIC Study Approach



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actual historical data for solar in upcoming years, this analysis can be updated with actual site-specific solar operations rather than data provided by NREL.

The incremental additional reserves need for each level of solar capacity can of can be found seen below in Table 4.

Table 4. Incremental MW Reserves Required by Solar Tranche

Month	Baseline (340 MW Solar)	Tranche 1 (341 to 973 MW)	Tranche 2 (974 to 1073 MW)	Tranche 3 (1074 to 1373 MW)
1	250	244.1	70.9	178.7
2	250	337.9	38.8	207.3
3	250	373.1	47.1	219.1
4	250	382.0	67.1	196.1
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7	250	310.8	66.6	167.0
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9	250	304.4	48.1	195.1
10	250	298.9	55.9	178.8
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12	250	233.1	53.8	116.3

Source: Guidehouse Study for DESC, June 2021

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[5] PROMOD is only capable of modeling a varying reserve requirement by month, not on hourly basis. The VIC is ~~solar generation-weighted~~weighted by whether or not solar is generating to avoid the biases that may arise when modeling an increased reserve requirement around the clock. ~~For example, the difference in total production costs during a midday hour where there is peak solar generation is weighted proportionality more than a shoulder hour where the sun may be rising or setting and there is less generation. At the same time, t~~This calculation excludes overnight hours where solar generation is zero.

[6] The discount rate was provided by DESC. It is consistent with any internal IRP and avoided cost modeling.

2.1 Key Assumptions

This study utilizes assumptions from DESC's Commission-approved Modified 2020 Integrated Resource Plan (IRP) RP8. Key assumptions are described in the subsections below. Guidehouse models inputs and dispatches PROMOD in real terms. As such, any inputs discussed in the following subsection as in real 2020 terms.

2.1.1 Existing Generating Resources

The existing non-solar generating units for DESC as modeled in this study are listed below in Table 5 for the year 2021. Current non-solar nameplate capacity totals 5,895 MW. Future additions and retirements to the system are listed in the next section. Differences between solar penetration across scenarios are discussed later in in Section 2.1.4.

The combined-cycles, ST Coal, ST Gas, and V.C. Summer nuclear plant provide the majority of baseload generation needed in DESC, with the ST Gas and CCs able to ramp up their output during peak hours. The CT Gas, Fairfield, and Saluda plants are used for reserves and peaking needs.

Plant and unit level operational parameters were provided by DESC to Guidehouse in order to benchmark the system against DESC's internal modeling, examples of key unit characteristics provided by DESC include:

- 8760 Solar Resource Shape (MW)
- Minimum Load (%)
- Full Load Heat Rate (MMBtu/MWh)
- Non-Fuel VOM ($/MWh)
- Must Run Status
- Minimum Uptime (Hours)
- Minimum Downtime (Hours)
- Expected Forced Outage Rate (EFOR) (%)
- Annual Maintenance (Hours)
- Startup Fuel Type and Requirements (MMBtu)

Table 5. DESC Modeled Units

Plant	Technology	Nameplate Capacity (MW)	Quick-Start	EFOR (%)	Heat Rate (MMBtu/MWh)
Wateree	ST Coal	684	No	3.6	9.85
Williams	ST Coal	610	No	4.3	9.74
Cope	ST Coal/ST Gas[1]	415	No	2.0	9.70
McMeekin	ST Gas	250	No	1.0	9.90
Urquhart	ST Gas	96	No	12.17	11.69
V.C. Summer	Nuclear	662[3]	No	2.0	10.00
Urquhart 1-4	CT Gas	97	Yes	5.0	18.93[4]
Coit	CT Gas	36	Yes	5.0	15.55
Parr	CT Gas	73	Yes	5.0	17.12[4]
Bushy Park	CT Gas	52	Yes	5.0	15.98
Hagood 4-6	CT Gas	141	Yes	5.0	11.62[4]
Urquhart	CC	484	No	0.9	7.43
Jasper	CC[2]	924	No	2.4	7.67[4]
Columbia Energy Center (CEC)	CC[2]	571	No	1.67	7.71[4]
Fairfield Pumped Storage	Hydro PS	576	No	N/A	N/A
Saluda	Hydro	198	No	N/A	N/A
Other Hydro	Hydro	26	No	N/A	N/A

[1]Cope fully transitions to Natural Gas in 2030
[2]Jasper and CEC are upgraded in 2023, raising their maximum capacity
[3]The capacity of V.C. Summer represents the amount of MW of the plant contracted withing DESC's system
[4]Plant weighted average full load heat rate, individual unit full load heat rates vary slightly
Source: Dominion Energy South Carolina

2.1.2 Modified 2020 Integrated Resource Plan 8

The DESC IRP filed on February 19, 2021 includes multiple pathways for the future evolution of the system. Guidehouse utilized Modified 2020 IRP Resource Plan 8 (RP8) with high demand side management as the basis for this study. There was one notable exception, which was to exclude any solar capacity additions outside of the existing 340 MW.

RP8 calls for the complete retirement of all coal units by 2030 and their generation replaced with a combination of gas and renewables. RP8 includes the retirement of the coal plants Wateree, 684 MW, and Williams, 610 MW, by 2028. The capacity will be replaced by a 553 MW combined cycle plant and 523 MW of gas turbines. The Cope plant 415 MW will transition to being fully natural gas fired in 2030. The first 100 MW storage unit is added in 2031, the rest are added outside of the forecast period. Additionally, demand side management will reach 1% of retail sales by 2021 reducing annual energy and peak demand.

Table 6. IRP Plan 8 Buildout and Retirements

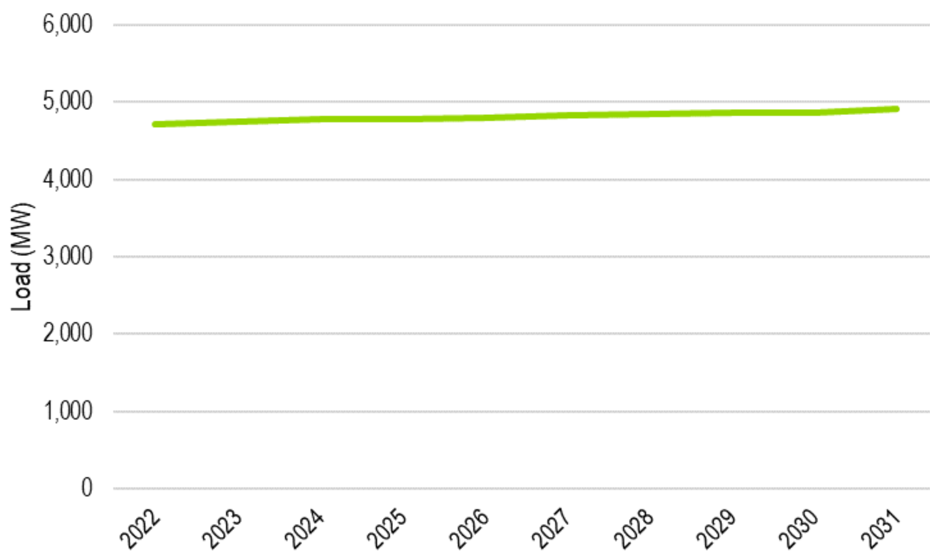
Year	Unit Name	Category	Change	Capacity (MW)
2022	Beulah Solar	Utility Solar	New Plant	75
2023	Columbia Energy Center	CC	Upgrade	638
2023	Jasper	CC	Upgrade	979
2028	Wateree	ST Coal	Retirement	684
2028	Williams	ST Coal	Retirement	610
2028	IRP Plan 8 CC	CC	New Plant	553
2028	IRP Plan 8 CT	CT Gas	New Plant	523
2030	Cope: 1	ST Gas	Upgrade	415
2031	IRP Plan 8 Storage	Battery Storage	New Unit	100

Source: Dominion Energy South Carolina, Modified 2020 Integrated Resource Plan

2.1.3 System Load

Figure 5 shows the forecasted annual system peak load[7] for the study period of 2022 to 2031. Both annual load and peak grow at a relatively constant and low rate, with a Compound Annual Growth Rate (CAGR) of approximately 0.55% and 0.47%, respectively, over the study period.

Figure 5. Annual Peak Demand



Source: Dominion Energy South Carolina, Modified 2020 Integrated Resource Plan

2.1.4 Solar Penetration Tranches

Guidehouse evaluated the following levels of solar penetration to account for both current solar resources under contract and potential future additions. The specific tranche sizes that Guidehouse evaluated for this study were chosen to align with the impact the projects have on the system and the project Purchase Power Agreement (PPA) structures.

[7] The system was simulated hourly and the forecasted load is used on an hourly basis.

- Baseline (0 to 340MW): The Baseline scenario includes the initial solar projects totaling approximately 340 MW whose PPAs do not include a VIC.
- Tranche 1 (341 to 973 MW): Tranche 1 includes existing non-solar-generation resources listed in Table 5 and the proposed Plan 8 changes listed in Table 6. The existing 340 MW of solar capacity that is included in the baseline case is listed in Table 7, while the 633 MW of solar additions that make up this tranche are listed in Table 8.

Table 7. Solar Projects with No VIC

Plant	Nameplate Capacity (MW)
Barnwell Solar	5.44
Cameron Solar II	4.08
Cameron Solar LLC	19.992
Champion Solar LLC	10.88
Nimitz Solar	8
Curie Solar	2
Estill Solar I	20.326
Estill Solar II	10.2
Gaston Solar I	10.2
Haley Solar LLC	8.16
Hampton Solar I	6.8
Hampton Solar II	19.992
Moffett Solar 1	71.4
Odyssey Solar LLC	8.16
Otarre Solar Park	1.62
Ridgeland Solar Farm I	10
Saluda Solar II LLC	3.4
Saluda Solar LLC	6.8
Shaw Creek Solar Farm	74.9
Southern Current One	10.2
Springfield Solar (SC)	6
St Matthews Solar	10.2
Swamp Fox Solar	10.88
TIG Sun Energy III	0.5

Source: Dominion Energy South Carolina

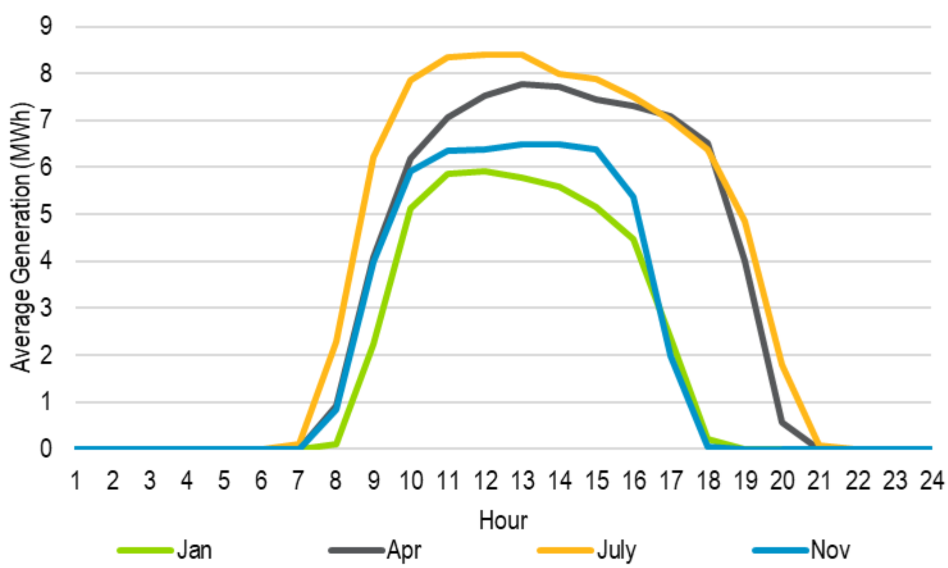
Table 8. Solar Projects in the 341 to 973 MW Tranche

Plant	Nameplate Capacity (MW)
Beulah Solar	75
Blackville Solar Farm	7
Blackville Solar II	20
Denmark Solar	6
Diamond Solar	8
Edison Solar	5
Gaston Solar II	7
Huntley Solar	75
Lily Solar	70
Midlands Solar	72
Palmetto Plains Solar	75
Peony Solar	39
Richardson Solar	4
Seabrook Solar	73
Trask East Solar	12
TWE Bowman Solar	75
Yemassee Solar	10

Source: Dominion Energy South Carolina

- Tranche 2 (974 to 1,073 MW): Tranche 2 includes all of the projects indicated for Tranche 1 as well as an additional 100 MW of solar resources. As this tranche does not represent any specific assets already under contract, it is modeled as a generic solar addition. Guidehouse models all intermittent generation as fixed transactions using an 8760 shape. The systemwide shape, as shown in Figure 6 using an existing asset as an example, was provided by DESC and has a capacity factor of 23.9%

Figure 6. Daily Solar Generation – Champion Solar 2022



Source: Dominion Energy South Carolina

- Tranche 3 (1,074 to 1,373 MW): Tranche 3 includes all the solar capacity represented in Tranches 1 and 2 as well as an additional 300 MW solar generic unit to account for potential future additions of solar capacity onto the system. This generic unit has the same parameters as the 100 MW generic unit found in the previous tranche.

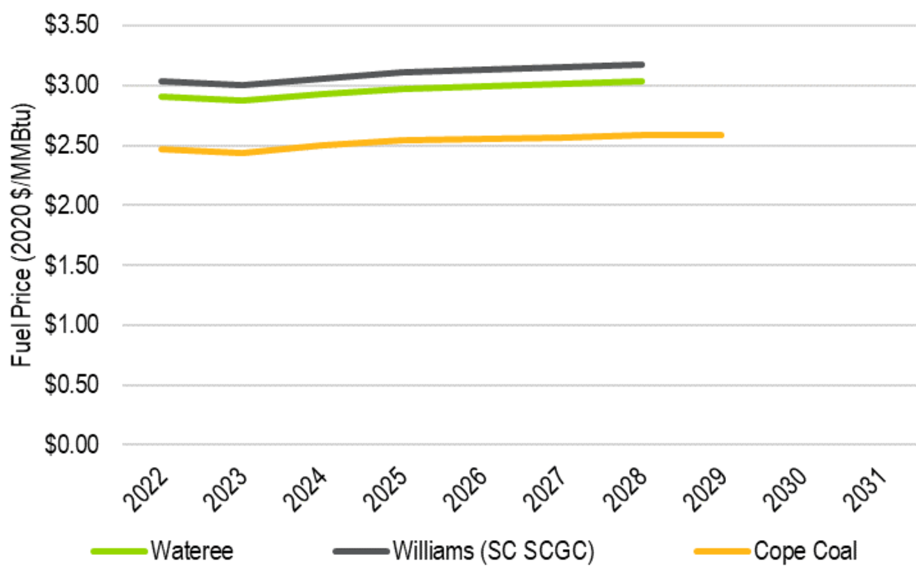
2.1.5 Fuel Prices

Plant specific fuel price streams were confirmed by Guidehouse and approved by DESC. Guidehouse utilizes the Gas Pipeline Competition Model (GPCM) to develop natural gas price forecasts. GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Guidehouse applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Guidehouse's view, insight, and detailed knowledge of the U.S. and Canadian natural gas markets.

Guidehouse receives basin and plant-level coal price forecasts from a third-party vendor. DESC reviewed and approved of the forecast coal prices modeled for their coal plants.

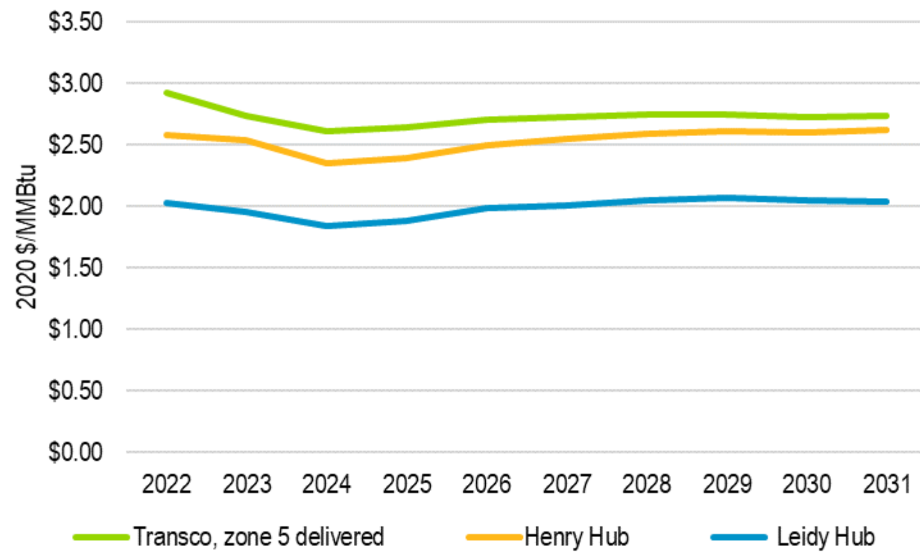
Annual coal and gas prices are shown in Figure 7 and Figure 8, respectively.

Figure 7. DESC Plant Coal Prices



Source: Guidehouse Spring 2021 Reference Case

Figure 8. Gas Price Forecast Across VACAR



Source: Guidehouse Spring 2021 Reference Case

2.1.6 Generic Expansion Beyond DESC

Guidehouse runs PROMOD nodally for the entire Eastern Interconnect (EI) and utilizes its own screening process, methodology, and model to generate the buildout of EI outside of DESC. Provided Guidehouse deems it likely, the most recent state policies, changes in regional capacity buildout, and anticipated demand curates a future buildout that includes the next generation of resources that will be supplying the grid. This allows Guidehouse to create a snapshot of a likely future of the EI. By modeling the system as a whole, Guidehouse is able to fully account for the dynamism of the grid. By having unique assumptions for each transmission zone, Guidehouse provides results that are accurate locally. Significant changes to expected capacity mixes in neighboring regions such as Duke Energy Carolina's (DEC), Duke Energy Progress's (DEP), and Santee Cooper will impact both the amount and the cost of energy that is available to be imported into DESC's system.

2.2 Modeling the System with PROMOD

Production cost models are a class of models that are used to complete analyses of electricity system costs. These models are appropriate for evaluating how system costs change when aspects of those systems change.

Guidehouse uses PROMOD as its primary production cost modeling tool. PROMOD is a commercially available software used by many utilities and ISOs, including PJM and MISO, for production cost modeling. There are other available production cost models and consistent results can be expected if a different model was used for the study.

Like all production cost models, PROMOD simulates system operation hourly to minimize the total operating cost while ensuring that generation and load are matched and that operating reserve requirements are met. The model also takes into account generator operating limits and transmission constraints. The key outputs of the system simulation are the hourly details of system operation including generation by unit and the hourly operating costs.

From PROMOD, the production costs can be calculated by summing:

- Fuel costs
- Variable operating costs
- Startup costs
- Emissions costs

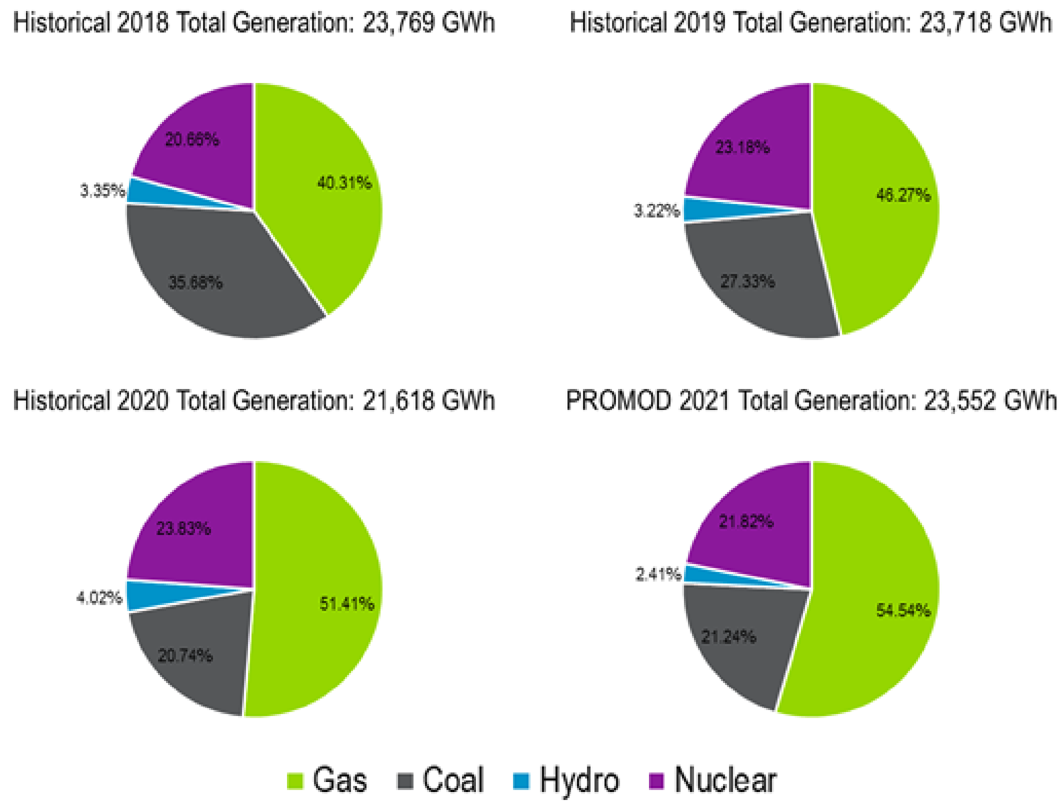
2.2.1 Benchmarking DESC

Guidehouse underwent a diligent process to benchmark the DESC system to recent actual operations. This included receiving operational information from DESC operations and system modeling teams which included:

- Hourly demand net energy efficiency
- Generation portfolio characteristics
- Renewable shapes
- Historical production by generating technology type
- Additions and retirements

After several iterations, the system was benchmarked considering both recent historicals and DESC's internal modeling. Guidehouse's IRP Plan 8 with High DSM Base scenario generation results for 2021 are shown in Figure 9 alongside recent historical generation data provided by DESC. Differences in the generation mix between the 2018 and 2019 actual generation compared to 2020 actual generation and the 2021 PROMOD run include the purchase of the Columbia Energy Center in 2018 (571 MW CC), divestment from a coal/biomass cogenerator in 2019 (85 MW Coal) and the temporary refurbishment of a Wateree unit (342 MW Coal) keeping it offline for most of 2020 and 2021.

Figure 9. Benchmarking Results



Source: Dominion Energy South Carolina, Guidehouse Study for DESC, June 2021

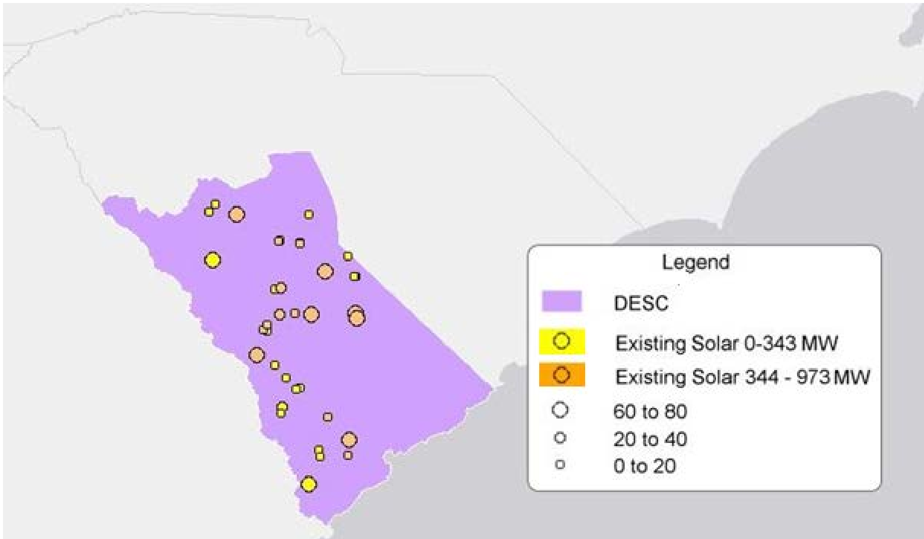
2.3 Forecasting Requirements to Integrate Solar

Guidehouse developed an approach to forecast the amount of load-following reserves needed with increasing renewable penetration. This approach relies on the NREL Solar Integration Data Sets to simulate renewable operation[8]. A key aspect of these shapes is that they are simulated historical operation of the assumed resources including the impacts of regional weather and geographic diversity. In the future, as DESC integrates larger amounts of solar and can obtain actual historical data for solar in upcoming years, this analysis can be updated with actual site-specific solar operations rather than data provided by NREL.

Each NREL solar dataset includes one year of historical 5-minute data. Forty sites of various capacities across DESC's area were selected to represent the geographic diversity as shown in Figure 10. NREL also provides corresponding 4-hour ahead hourly schedules for each simulated solar plant. Changes to operating reserve requirements due to increasing solar penetration are driven by the level of forecast uncertainty in solar generation. In order to calculate this, the forecasted solar-generation data set is compared to the real-time solar-generation dataset to calculate the generation variance from the forecast, from which the area-control-error (ACE) contribution due to renewable uncertainty can be calculated (ACE = Output – Schedule). The ACE contributions of individual sites are scaled appropriately based on the actual capacity assumed to be at the given location.

[8] https://www.nrel.gov/grid/solar-integration-data.html

Figure 10. DESC Solar Sites



Source: EV Maps, NREL Solar Integration Data Set

To comply with NERC's Reliability Based Control Standard BAL-001-2, a Balancing Authority Area (BAA) must operate such that its clock-minute average reporting ACE does not exceed its Balancing Authority ACE limit (BAAL) for more than 30 consecutive minutes. Based on the BAA's frequency bias and historical variability of interconnection frequency, a worst-case scenario BAAL is determined. A BAA is assumed to call upon its load-following resources if violating the BAAL for 15 consecutive minutes (allowing 15 minutes to come back into compliance). For each hour of renewable operation, the load-following and regulation resources needed to prevent a NERC violation is recorded.

DESC needs to hold sufficient reserves to be able to respond to the worst-case downward variance of solar generation while maintaining reserve requirements. Guidehouse assumes the reserve requirement is the 90th percentile of instances under the worst-case scenario BAAL for each month so to not overestimate the need. The monthly reserve requirements for each scenario with the 350 MW of contracted solar (named and undisclosed) is displayed below in Table 9.

Table 9. Incremental Reserve Requirements by Solar Tranche

Reserve (MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Tranche 1	244	338	373	382	358	331	311	307	304	299	275	233
Tranche 2	71	39	47	67	87	68	66	40	49	56	48	54
Tranche 3	179	207	219	196	189	178	167	167	195	179	164	116

Source: Guidehouse Study for DESC, June 2021

DESC already operates for most hours with enough excess flexible generation to meet this need on their system. However, in some hours, the system will need to hold back additional reserves and operate at a less efficient point in order to meet the additional demands of variability from solar integration.

2.3.1 Data Sources

The amount of solar variability that DESC operators will need to be able to respond to is driven by the level of forecast uncertainty for solar generation in the territory. The challenge is that there is a short track record in the system for how much solar uncertainty there is. DESC does not have data that can be used to calculate the distribution of the difference between solar-generation forecasts and the actual solar generation.

To be able to complete the study, Guidehouse used two sources of solar data:

- The hourly shape for solar generation that is input into PROMOD is developed from an aggregation of real solar-generation hourly shapes from DESC.
- The forecast uncertainty is developed from the NREL Solar Integration Dataset[9]. This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites across the U.S.

2.3.2 Geographic Diversity

An important part of this analysis is to consider geographic diversity when forecasting the solar uncertainty. Spreading solar generation geographically can reduce overall uncertainty, even in a service territory as geographically compact as DESC; however, because DESC's service territory is so geographically compact, the impact of considering geographic diversity in this study is minimal.

Without considering geographic diversity, the solar uncertainty would be higher. To avoid this, the forecast error analysis was completed using the NREL data located nearest to each of the existing and planned solar plant locations. The remaining 400 MW of solar which are planned but have no specified location were divided into eight 50 MW sections and randomly assigned the same coordinates as other existing solar plants in DESC's service territory. Because the NREL dataset includes sample solar plants of different sizes at the location, the 4-hour ahead and actual available capacity was scaled to the maximum MW of the closest DESC plant they represent. Then, by averaging the scaled forecast error across all locations, the impact of any one particular solar profile skewing the total operating reserves needed was minimized.

2.3.3 Detailed Approach

The solar forecast error is calculated as the difference between the 4-hour ahead forecast generation and the 5-minute actual solar generation. This is appropriate because, as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, DESC will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield and Saluda, any of the CCs and STs that may already be online, as well as the CTs that are capable of starting quickly.

The following methodology is used to calculate the solar forecast error.

1. Calculate the 4-hour ahead solar forecast as the average of all active solar sites located around the DESC service territory.

[9] https://www.nrel.gov/grid/solar-integration-data.html

2. Calculate the 5-minute generation as the average of the actual generation at the same sites.
3. Calculate the 5-minute variance in solar generation as the difference between the forecast and the actual in every 5-minute period.
4. Calculate the solar variance DESC must respond to as the 15-minute moving average of the 5-minute forecast error.[10]

The result of this analysis is a comprehensive set of data that gives the amount that actual solar generation varied from the 4-hour forecast. This can be evaluated by month, season, or time period to determine how operators would need to plan for solar uncertainty.

2.4 Calculating Integration Costs

To calculate the integration costs of the various solar buildouts, PROMOD was run twice for each tranche with nearly identical input assumptions, with the only difference being the change in levels of operating reserves as calculated using the methodology explained above in Section 2.3. The first PROMOD run for each tranche used the operating reserve requirement from the previous tranche's solar penetration, while the second run incorporated operating reserves calculated with the current solar penetration. The difference of the system costs of the two PROMOD runs were then compared to calculate the cost of integrating solar.

Since PROMOD does not allow for hourly changes in operating reserves, to calculate the impact of integrating solar, the hourly production costs were weighted by the solar generation of the newest units. This means that differences in production cost at night do not impact integration costs~~ while the hours when solar generation becomes its largest, impact the integration cost the greatest~~. This prevents bias in the integration cost calculation for hours when solar would not reasonably be expected to contribute to generation. With many baseload generators ramped down to less than full capability overnight, and most combustion turbines that are capable of providing quick-start reserves not in use, the amount of reserves available overnight and in other non-solar is greater in the baseline scenario than is required by the ensuing tranches thus the increased reserve requirement is not a binding constraint in those hours anyways.

This study includes a comparison of the system costs for three different levels of solar penetration:

0. Baseline: Solar with existing PPA's that do not include a VIC – totaling 340 MW.
1. Tranche 1: Solar with existing PPA's, including 633 MW that currently have a VIC clause – totaling 973 MW.
2. Tranche 2: Solar with existing PPA's and an additional 100 MW procurement – totaling 1073 MW.
3. Tranche 3: Solar with existing PPA's and an additional 400 MW procurement – totaling 1373 MW.

[10] Dominion Energy South Carolina must meet NERC Reliability Based Control Standards which give the utility up to 30 minutes to respond to any large deviation between load and generation. 15 minutes is chosen for this study as Dominion Energy South Carolina would want to respond well before 30 minutes to ensure sufficient time to avoid exceeding the 30-minute limit.

Each level of solar penetration was given operation reserve requirements based on the current level of solar penetration as well as the previous. In the baseline, 250 MW an operating reserve requirement was used for comparison as that represents what the system would operate without any additional solar generation.

Table 10. Solar and Reserve Scenarios

Baseline (340 MW Solar)	Tranche 1 (340 to 973 MW)	Tranche 2 (974 to 1073 MW)	Tranche 3 (1074 to 1373 MW)
Baseline Reserves	Baseline Reserves	-	-
-	Tranche 1 Reserves	Tranche 1 Reserves	-
-	-	Tranche 2 Reserves	Tranche 2 Reserves
-	-	-	Tranche 3 Reserves

Source: Guidehouse Study for DESC, June 2021

Beyond simply holding additional reserves with the current power system, DESC has the ability to add new resources such as CT gas or storage that can provide reserves. If new units are added as a mitigation option, then new resources are added to the set that is available to DESC to meet load and reserve requirements. The capital costs of the new resources would be added to the total mitigation costs for comparing between the Baseline and change scenarios. The study tests whether additional resources can be used to reduce the total integration costs.

The overall change in system cost was then divided by the MW of solar added in the latest tranche to give a per MW basis for the latest addition. The net present value was then calculated over the forecast period.

3. The Cost of Integrating Solar

3.1 Additional Reserves Required

As discussed in Section 2.3, DESC will need to hold an increasing amount of reserves as solar penetration increase. The reserves required by month for each level of solar penetration under this study can be seen below in Table 11. These values are cumulative, representing the total operational reserve requirement for full amount of solar capacity modeled in the tranche inclusive of prior tranches, not incremental reserves for only the incremental solar capacity of the tranche. The number does not change year to year for this study as it was assumed the additional solar capacity associated with the tranche would be online from the beginning of the forecast.

Table 11. Total Reserves Required by Solar Tranche

Month	Baseline (340 MW Solar)	Tranche 1 (341 to 973 MW)	Tranche 2 (974 to 1073 MW)	Tranche 3 (1074 to 1373 MW)
1	250	494.1	565.0	743.7
2	250	587.9	626.7	834.0
3	250	623.1	670.2	889.3
4	250	632.0	699.1	895.2
5	250	607.6	694.9	884.3
6	250	580.5	648.8	827.4
7	250	560.8	627.4	794.4
8	250	556.9	607.3	773.5
9	250	554.4	602.5	797.6
10	250	548.9	604.8	783.6
11	250	525.2	572.5	736.5
12	250	483.1	536.9	653.2

Source: Guidehouse Study for DESC, June 2021

3.2 Variable Integration Costs

The levelized VIC over the forecast period for each tranche can be seen in Table 12. The VIC was calculated as described in Section 2.4 for each year and tranche. The net present value was taken for the 10-year study period, using an 8.5797% discount rate[11], and then divided by the number of years.

[11] The discount rate was provided by DESC. It is consistent with any internal IRP and avoided cost modeling.

Table 12. Variable Integration Cost by Solar Tranche

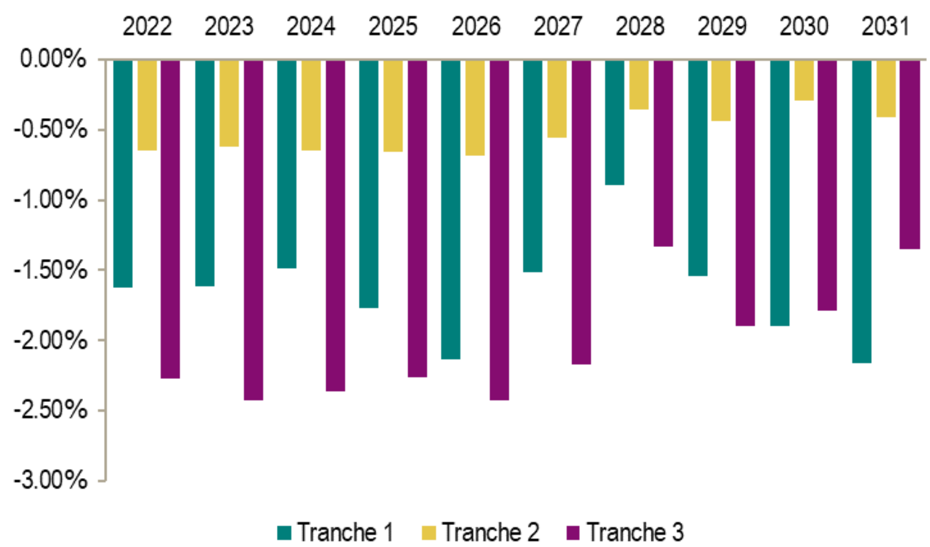
Solar Tranche	VIC ($/MWh)
Tranche 1 (341 to 973 MW)	$1.8016[12]
Tranche 2 (974 to 1073 MW)	$3.4301
Tranche 3 (1074 to 1373 MW)	$4.6345

Source: Guidehouse Study for DESC, June 2021

Annual cost and solar generation data for the forecast period can be found in Appendix B.

Barring other changes to the system, as solar penetration increases the cost to integrate it increases at a faster rate than the operating reserve requirement increases. This is driven by the need to operate the system in an increasingly inefficient manner in order to hold back enough flexible generation to meet the reserve requirement. Figure 11 shows the annual reduction in realized capacity factor for DESC's CC fleet for all three tranches as driven by the increased operating reserve requirement. Ramping down production from CC's to meet increased reserve requirements leads DESC to have to rely on less efficient, more expensive generating assets to make up the shortfall. This includes ramping up production from coal plants (until they retire), steam gas plants, and combustion turbines in addition to increasing net imports.

Figure 11. Annual Change in CC Capacity Factor With Increased Reserves Versus Without



Source: Guidehouse Study for DESC, June 2021

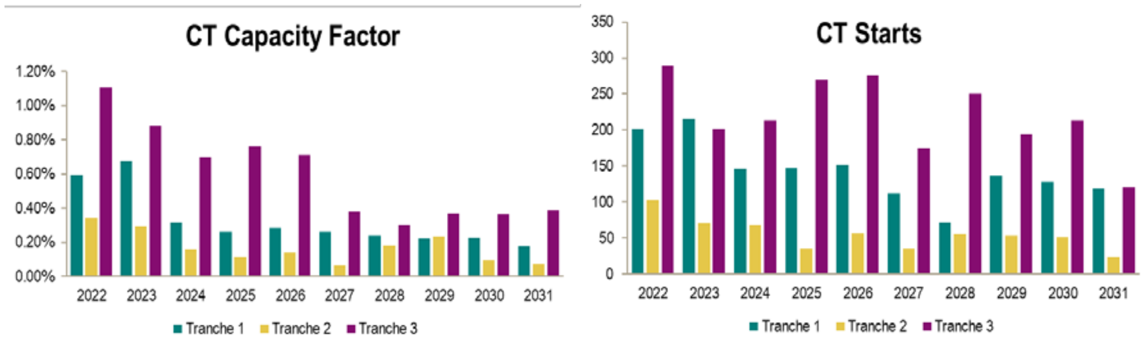
Decreases in realized annual capacity factors for DESC's CC fleet driven by increased reserve requirements in Tranche 2 and Tranche 3 as compared to Tranche 1 are greater proportionally than the increase in solar penetration for each. The increase in solar penetration for Tranche 2 (100 MW) is less than 1/6th the increase in solar penetration for Tranche 1 (633 MW), and the

[12] Roughly 35 MW of capacity included Tranche 1 from Blackville Solar Farm, Denmark Solar, Trask East Solar, and Yemassee solar have PPA's with DESC that include a VIC of $2.29/MWh, greater than the VIC calculated here for the tranche. The presence of a fixed VIC in these 4 contracts does not materially impact this analysis.

increase in reserve requirement for Tranche 2 as compared to Tranche 1 is proportionally similar, but the decrease in CC capacity factor driven by increase in reserve requirement for Tranche 2 is roughly 1/3rd that driven by Tranche 1. Meanwhile, the incremental solar penetration and increase in reserve requirements for Tranche 3 are roughly half of those for Tranche 1 but the decrease in CC capacity factor attributable to the increased reserve requirement for Tranche 3 is greater than or equal to that from Tranche 1 in most forecast years.

Similar to the decrease in CC capacity factor, the change in CT utilization for each tranche as compared to the prior is greater proportionally than the increase in solar penetration or reserves required. Figure 12 shows the increase in annual capacity factor and total turbine starts for combustion turbines driven by increased operating reserve requirements.

Figure 12. Annual Increase in CT Utilization With Increased Reserves versus Without



Source: Guidehouse Study for DESC, June 2021

As flexible generation is ramped further and further down to meet increasing reserve requirements, increasing their own operating costs on a $/MWh basis due to being less efficient operating below their maximum capabilities, the generating assets that DESC can call on to replace their energy are more and more expensive to operate. This demonstrates that each incremental intermittent solar capacity addition and its resulting increase in reserve requirements will have a more significant impact on DESC operations and costs than the prior incremental intermittent solar capacity addition.

4. Demonstrating the Need for Additional Reserves

DESC's grid reliability is threatened when there is insufficient system ramping capability to meet potential drops in solar generation while maintaining the required reserves.

4.1 Reliability Challenges without Adding Reserves for Variable Integration

In each hour of the forecast, the following process is used to calculate whether DESC has any reliability issues from solar generation that need to be mitigated.

1. Calculate the total amount of ramping capability on the system.
    - This is the sum of the ramping up capability of online units and the capacity of quick-start units that can be turned on.
    - This will be at least the total reserve requirement (250MW) but is typically more dependent on actual system operations.
2. Calculate the potential lost solar generation due to forecast uncertainty.
3. Subtract the lost solar generation from the system ramping capability.
4. Flag any hours in which the minimum reserve requirement is not met as reliability violations.

Table 13 shows 3 sample hours from the Tranche 1 (340 to 973 MW) analysis in which there are reserve shortfalls if the system only requires 250 MW reserves but includes risk of solar generation being out. These sample hours are the reason that DESC operators must hold more reserves for the solar uncertainty.

Table 13. Example of Hours with Reserve Shortages

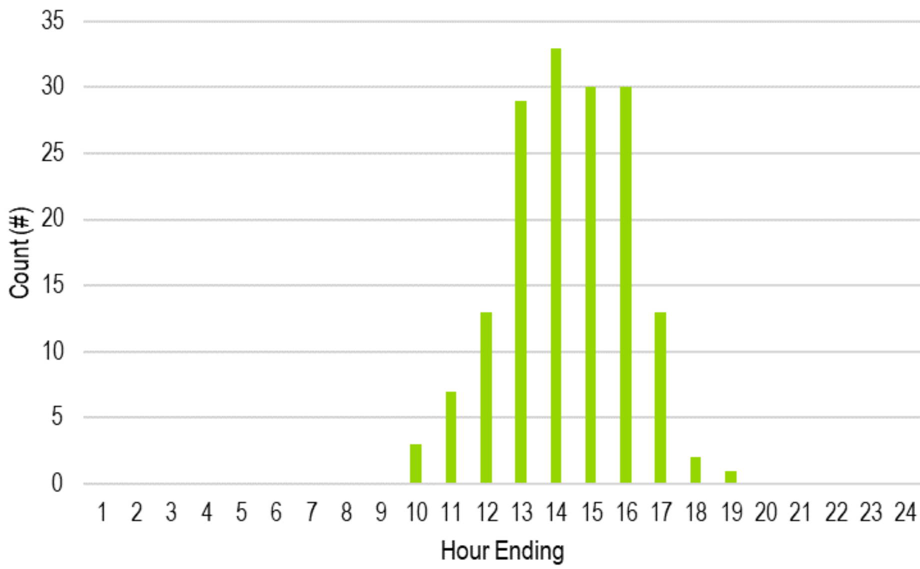
Hour	Load	CC Ramp (Gen)	CT Ramp (Gen)	Saluda Ramp (Gen)	Fairfield Ramp (Gen)	Interruptible Load	Total Reserves Online	Risk of Solar Shortfall	Reserves Shortage
8/28/23 4pm	4,388	32 (1,662)	321 (174)	196 (19)	0 (0)	100	649	468	69
2/22/25 4pm	2,294	0 (0)	495 (0)	177 (30)	0 (0)	100	772	558	36
7/21/27 1pm	4,305	38 (1,941)	397 (98)	196 (17)	0 (0)	100	731	537	56

Source: Guidehouse Study for DESC, June 2021

While there are more than the minimum reserves in most hours, there are a material number of hours in each scenario for which additional reserves would need to be held for the solar generation.

Figure 13 shows the annual distribution by hour of the reserve shortfalls. These hours are concentrated during the late afternoon, when forecasted solar generation is at its highest level and thus so is the potential forecast error, and in the evening when solar beings to rapidly ramp down.

Figure 13. Reserve Shortfalls by Hour in Tranche 1 with Baseline Reserves



Source: Guidehouse Study for DESC, June 2021

4.2 Calculating the Additional Reserve Requirements

The analysis in Section 4.1 demonstrates that if DESC does not hold additional reserves then there will be a significant number of hours in which reliability violations occur. That analysis does not show the amount of additional reserves that must be held.

When planning operation, DESC only knows the forecast for solar generation and must plan for the worst case. This means that the utility must hold sufficient reserves in each case to be able to respond to the worst-case drop in solar given the forecast.

For each solar penetration scenario, the maximum expected drop in solar generation for each month was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met. The reserve requirement changes by month as the potential solar forecast error can vary greatly depending on the expected irradiance and shifting unpredictability of weather patterns. Once all the solar capacity for each scenario is online the monthly reserve requirements do not change year over year. As shown previously in Table 11 additional reserves vary by month in all solar penetration scenarios which are greater than the current reserves held by DESC. One aspect of holding reserves is DESC knows the level of expected solar generation prior to setting the reserves to be held, so the required reserves needed to compensate for a potential drop in solar would be adjusted on a daily or hourly basis.

Previously, Table 11 showed the maximum needed reserves necessary, but when calculating the costs, it is important to consider that holding an increased level of reserves is only required during hours in which solar assets are generating. To ensure that the analysis does not overestimate the costs to integrate reserves at any of the penetration levels, PROMOD was run with each of these levels of reserves and the results were formulated based specifically on the increased amount of solar generation hourly as compared to the previous tranche thereby reducing bias by eliminating from the calculations any hours in which solar is not generating~~ and more heavily weighting hours where solar generation is high as compared to hours where solar generation is low~~.

4.3 Reserve Requirements for Additional Solar

The additional reserve requirements for Tranche 1 presented in Table 11 were developed for the solar projects that have already contracted with DESC. The additional reserve requirements for Tranche 2 and Tranche 3 are estimated for future solar projects that are not currently in development, but by maintaining the same methodology as was used to calculate the reserve requirement for Tranche 1 the integration requirements for both tranches can be calculated.

For each additional tranche of solar, the variable integration charge increases in a non-linear fashion. This is driven by the fact that, absent any other changes to the system or capacity mix, an increased reserve requirement necessitates relying on generators that are less efficient and more expensive to operate than the prior operating reserve requirement associated with a lower level of solar penetration.

5. Mitigation Options and Integration Costs

5.1 Potential Mitigation Options

The mitigation needed to integrate solar generation is to hold additional reserves that will be available if actual solar generation is less than forecasted. There are three broad mechanisms for DESC to do this:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure additional quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline[13].
3. Procure additional baseload resources, such as CC gas units, that will displace existing baseload generation allowing for that capacity to displace the less efficient units currently providing operating reserves.

In this analysis, the cost of holding additional reserves is calculated first. This is then compared to the cost of adding new resources to check whether there is a lower cost approach to procuring the needed reserves. The integration cost for the solar resources is the levelized cost difference of the system costs with and without additional reserves.

Section 5.3 presents a third option in which the solar projects can add storage or operate in such a way that DESC's reserve requirements do not increase. If a project can meet the requirements to ensure this, then it is appropriate to exclude any integration impacts from the analysis of the avoided costs for that specific project.

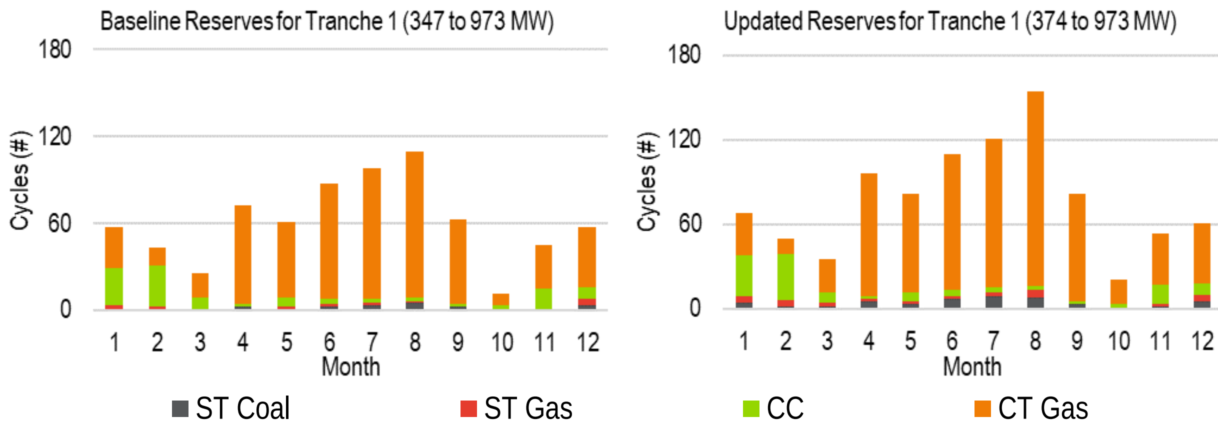
5.2 System Impacts of Holding Additional Reserves

In most hours, especially overnight, DESC holds more than the minimum necessary reserves through their least-cost security-constrained dispatch. This means that adding to the reserve requirement in the simulation is a non-binding constraint that does not materially influence the system operation in those hours. However, in hours in which DESC holds the minimum or close to the minimum amount of reserves, some resource generation levels will have to be changed.

PROMOD solves for the least-cost dispatch while respecting the additional reserve requirements. To a large extent, additional reserves come from reducing the generation from CC units so that they are providing more flexibility. ST units are turned on to ensure that load can be met. Figure 14 shows the comparison of the starts per month in the Tranche 1 analysis with and without additional reserves being held. As would be expected, the cycling increases with the additional reserves as the CTs and STs must turn on to be available.

[13] Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because Dominion Energy South Carolina cannot implement it unilaterally but only with technological changes by the solar facility owners.

Figure 14. Comparison of Unit Cycling in 2026 for Tranche 1



**Cope is included as in the ST Gas category*
Source: Guidehouse Study for DESC, June 2021

The most significant driver of the integration costs are increased fuel and operating costs. This is because less efficient units must be online to provide energy in order to allow more flexible units to provide reserves; those more flexible units must frequently operate at an intermediate level below their maximum capabilities, which is less efficient and thus more expensive per MWh than operating a max; and there are increased startup costs due to additional cycling.

There are also additional maintenance and fuel costs associated with ramping generating resources up and down very quickly when renewable generation varies. Those additional costs were not considered in this analysis, rather Guidehouse maintained a conservative approach in only considering the costs to maintain reserves and excluding the costs from the additional stress and reduced efficiency from matching short-term variability of solar generation.

5.3 Alternative Variable Generation Integration Approaches

In the Tranche 1 analysis, the NPV across the 10-year forecast period of the cost of holding additional reserves for variable integration is \$23.6M, driven by the need for additional of ~230-380 MW of operating reserves (which vary by month) which drives a need for DESC to operate the system differently than would be necessary without an increased operating reserve requirement. There are two potential alternatives to this solution: either (1) DESC can add more resources that will provide operating reserves, or (2) the solar projects themselves must add storage or operate more flexibly.

5.3.1 DESC Adds Resources

If DESC can add resources that can provide these reserves for less than incremental cost, then it would be possible to reduce the overall integration costs of solar to the system. The best options are quick-start gas CTs or battery storage for providing reserves. This study considered the following resources and costs[14].

- Quick-start CT - \$710/kW overnight cost

[14] Overnight capital costs based on independent Guidehouse analysis using publicly available data filed by utilities with the EIA.

- Natural Gas Combined Cycle (NGCC) - $985/kW overnight cost
- 2-hour Lithium-Ion Battery - $1,100/kW overnight cost[15]
- 4-hour Lithium-Ion Battery - $1,880/kW overnight cost

At a high level, this implies that DESC could alternatively add approximately 33 MW of quick-start CT, 21 MW of 2-hour battery, or 13 MW of 4-hour battery at the same cost incurred by carrying more reserves. None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation[16]. This also implies that DESC could alternatively add approximately 24 MW of NGCC capacity, but in addition to not being sufficient to meet additional reserve requirements it would also have to be spinning to provide reserves which would have additional implications on system dispatch and costs.

While additional resources are not currently feasible for reducing integration costs in any of the solar penetration scenarios, DESC should continue to monitor the need for reserves and the technology costs of mitigation options. The ability to provide reserves with batteries or CTs caps the integration cost of solar to the cost of these new resources. If batteries decline in price more sharply than expected, they may become a feasible mitigation option even with Tranche 2 or Tranche 3 levels of solar during this study period[17].

5.3.2 Solar Projects Add Storage or Otherwise Operate at Forecasted Output

The need for DESC to maintain additional reserves to integrate additional intermittent solar capacity, and thus the need for a VIC, is driven by forecast uncertainty. However, by including flexible terms or storage equipment at the inception of the project, the forecast uncertainty could be significantly reduced or potentially eliminated.

The following are potential changes that would enable a solar or solar plus battery project to operate flexibly and reduce the need for DESC to hold additional reserves:

- Implement “flexible solar” operations allowing DESC to control the generation from the project[18]
- Installation of storage such that any solar generator can make up the shortfall in generation by replacing all of the scheduled energy of the project when called upon by DESC.

Allowing DESC to operate the solar projects as “flexible solar”, which is an operating mode in which the solar project can be dispatched up and down by the system, could mitigate the need for additional reserves. In order for DESC to operate a fully flexible solar project, the project owner would have to allow DESC to schedule and manage generation output. DESC’s objective would be formulating and executing a dispatch schedule to optimize overall system reliability and operating costs versus maximizing output and profits for any specific generators. As a result, flexible solar could reduce a developer’s revenues as DESC would likely curtail output

[15] Note that this cost assumes technology improvement and cost declines through 2031.

[16] To do a full analysis of mitigation with additional resources it would be necessary to also calculate additional benefits and costs associated with owning and operating these resources. The current analysis is only a screening to determine whether the additional of these resources will reduce the overall integration costs.

[17] Note that if solar units were operated to provide flexibility to the system, the integration costs borne by Dominion Energy South Carolina would be reduced.

[18] The specific rules allowing DESC to control the project operations will need to be defined in contracts.

when the cost of the additional reserve requirements outweighs the lower fuel cost of the curtailed solar.

Co-locating an appropriately sized battery with the solar project is another possibility for meeting these requirements. However, adding on storage capabilities would significantly increase the capital investment required for a solar facility. The impact of increased investment requirements would be to either materially reduce profits for developers or, if negotiated into the PPA, increase costs that are ultimately passed onto DESC customers.

It is appropriate and necessary for DESC to work with solar project owners to evaluate ways to meet the Mitigation Protocols filed by DESC on June 1, 2020 in Docket 2019-184-E or otherwise reduce generation uncertainty.

Appendix A. Market Modeling Process

Guidehouse's market modeling approach relies on a multifaceted approach for modeling and simulating the energy market and studying the performance of energy assets in the marketplace. Guidehouse's approach relies on the involvement of numerous subject matter experts with specific knowledge and understanding of several fundamental assumptions, such as fuel pricing, generation development, transmission infrastructure expansion, asset operation, environmental regulations, and technology deployment. From our involvement in the industry, Guidehouse has specific and independent views on many of these fundamental assumptions based on our knowledge and understanding of the issues. Provided below is an overview of the modeling process.

A.1 Electric Market Simulation

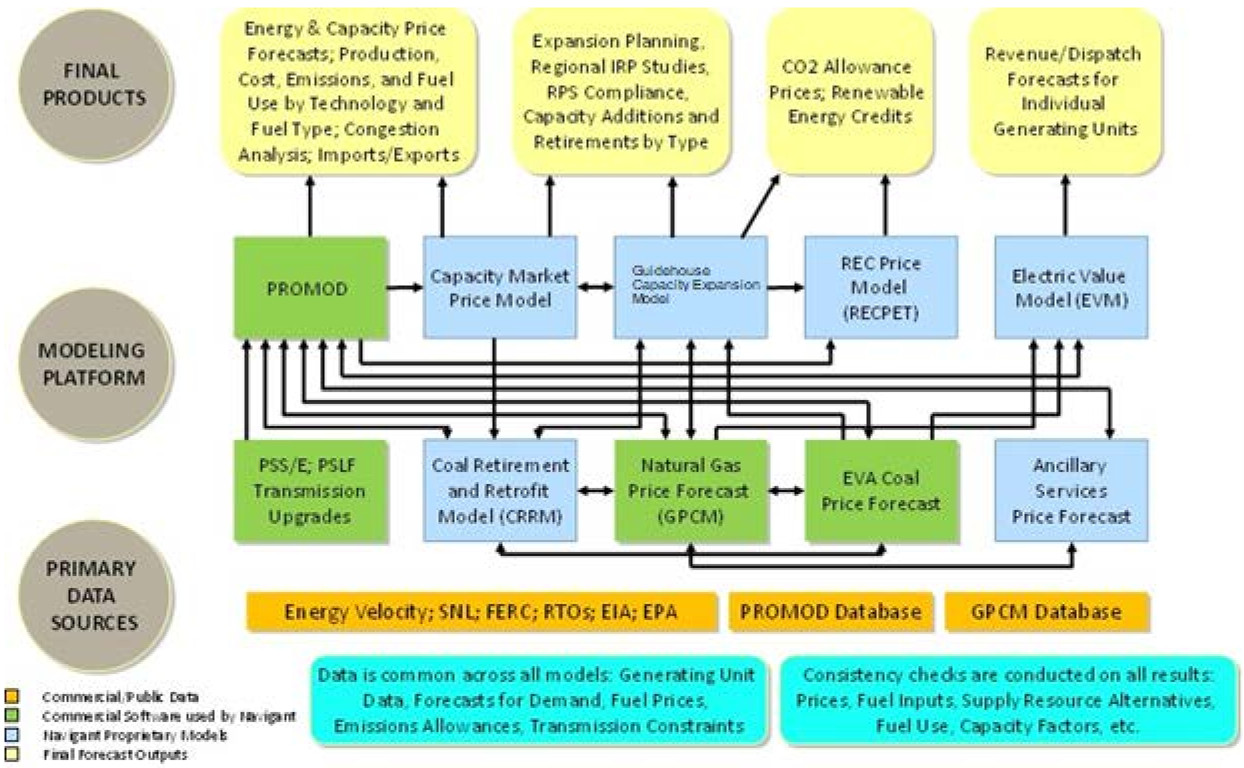
A diagram depicting the models used in Guidehouse's market modeling can be seen in Figure 15. Guidehouse utilizes a fully integrated suite of models to accurately simulate the operations of electric markets. In addition to utilizing commercial software such as PROMOD and GPCM, Guidehouse conducts extensive research into local, state, and federal policies and regulations that will impact energy markets, near-term generator additions and retirements, load forecasts, and other market developments. Guidehouse maintains proprietary models for capacity expansion planning that take into account expected generator retirements, load growth, RPS requirements, reserve margin requirements, and the levelized cost of entry for various generating technologies.

Guidehouse uses PROMOD, a commercially available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission resources on a nodal basis in wholesale electric markets. PROMOD dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The choice of generation is determined by the generator's total variable cost given operating constraints such as ramp rates (for fossil resources) or water availability (for hydraulic resources), and transmission constraints. The total variable cost of the marginally dispatched unit in each hour sets the hourly market clearing price. All generators in the same market area that are selected to run receive the same hourly market clearing price adjusted for losses and congestion, regardless of their actual costs. The Locational Marginal Prices (LMPs) produced by PROMOD compose Guidehouse's structural market price forecasts. Guidehouse does not employ bid-adders or other exogenous adjustments to prices in the PROMOD forecast.

Within PROMOD, production costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outage, startup, unit ramping, minimum up time and downtime, and other characteristics are factored into the simulation. Supply offer prices are simulated for each unit within PROMOD that correspond to the minimum price the unit owner is willing to accept to operate the unit. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each unit's fuel price multiplied by the incremental heat rate, plus variable operations, emissions, and variable maintenance costs.

Where relevant (primarily for thermal units), the unit offer price also incorporates the unit's startup and no-load costs. The start cost component includes fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The no-load cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

Figure 15. Guidehouse's Market Simulation Modeling Process



Source: Guidehouse

PROMOD has several distinguishing features that qualify it for application in electric power forecasting and related studies. These features include the following:

- Individual transmission line modeling
- Detailed and flexible unit commitment and dispatch modeling
- Modeling of operational transmission constraints (e.g., operating nomograms)
- Calculation of security-constrained dispatch schedules
- Hourly modeling of loads and resource operation

Guidehouse also uses the GPCM to develop our Reference Case Gas Price Forecast. GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Guidehouse applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Guidehouse's view, insight, and detailed knowledge of the U.S. and Canadian natural gas markets. Adjustments are made to the model to reflect accurate infrastructure operating capability as well as the rapidly changing market environment regarding economic growth rates, energy prices, gas production growth levels, demand by sector and natural gas pipeline, storage, and Liquified Natural Gas (LNG) terminal system additions and expansions. To capture current expectations for the gas market, this long-term monthly forecast is combined with near-term New York Mercantile Exchange (NYMEX) average forward prices for the first two years of the forecast.

Appendix B. Variable Integration Cost by Year

Figure 16. VIC Breakout for Tranche 1 (341 to 973 MW)

Year	Total Costs w/ Inc. Reserves (Nom $)[1]	Total Costs w/o Inc. Reserves (Nom $)[1]	Solar Generation (MWh)[2]	VIC (Nom $/MWh)[3]
2022	$282,156,426	$279,225,844	1,305,665	$2.24
2023	$280,164,813	$278,088,551	1,319,961	$1.57
2024	$284,043,563	$280,183,194	1,304,577	$2.96
2025	$298,669,042	$292,869,829	1,303,972	$4.45
2026	$314,827,987	$308,604,983	1,313,101	$4.74
2027	$328,909,942	$322,834,469	1,309,823	$4.64
2028	$319,739,783	$317,269,932	1,319,397	$1.87
2029	$303,991,547	$301,810,224	1,320,199	$1.65
2030	$311,518,168	$309,775,004	1,318,981	$1.32
2031	$322,264,148	$320,473,636	1,320,265	$1.36

[1] Costs are weighted by hourly solar generation.
[2] Solar generation is from the model runs with increased reserve requirements and includes any potential curtailment.
[3] The VIC is weighted to account only for solar-generation hours only.
Source: Guidehouse Study for DESC, June 2021

Figure 17. VIC Breakout for Tranche 1 (974 to 1073 MW)

Year	Total Costs w/ Inc. Reserves (Nom $)[1]	Total Costs w/o Inc. Reserves (Nom $)[1]	Solar Generation (MWh)[2]	VIC (Nom $/MWh)[3]
2022	$275,704,906	$274,721,307	208,910	$4.71
2023	$272,248,536	$270,925,306	206,930	$6.39
2024	$269,784,716	$268,984,632	195,517	$4.09
2025	$289,867,548	$288,475,331	195,937	$7.11
2026	$309,658,077	$308,276,383	203,728	$6.78
2027	$322,284,195	$320,481,533	199,743	$9.02
2028	$313,983,600	$313,428,428	203,890	$2.72
2029	$299,698,129	$299,046,047	207,058	$3.15
2030	$307,189,356	$306,464,017	205,538	$3.53
2031	$317,892,738	$317,239,631	206,659	$3.16

[1] Costs are weighted by hourly solar generation.
[2] Solar generation is from the model runs with increased reserve requirements and includes any potential curtailment.
Source: Guidehouse Study for DESC, June 2021

Figure 18. VIC Breakout for Tranche 3 (1074 to 1073 MW)

Year	Total Costs w/ Inc. Reserves (Nom $)[1]	Total Costs w/o Inc. Reserves (Nom $)[1]	Solar Generation (MWh)[2]	VIC (Nom $/MWh)[3]
2022	$270,317,960	$265,750,652	624,409	$7.31
2023	$269,029,409	$263,842,491	611,927	$8.48
2024	$269,778,256	$264,813,271	575,343	$8.63
2025	$290,115,195	$285,522,104	575,445	$7.98
2026	$307,284,186	$302,713,764	600,999	$7.60
2027	$319,654,709	$313,614,167	584,702	$10.33
2028	$310,388,437	$307,808,408	604,837	$4.27
2029	$292,374,941	$289,623,123	615,490	$4.47
2030	$299,412,450	$296,673,010	608,016	$4.51
2031	$309,382,769	$306,968,244	612,154	$3.94

[1] Costs are weighted by hourly solar generation.
[2] Solar generation is from the model runs with increased reserve requirements and includes any potential curtailment.
[3] The VIC is weighted to account only for solar-generation hours only.
Source: Guidehouse Study for DESC, June 2021